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Article

Balancing Fiscal, Energy, and Environmental Concerns: Analyzing the Policy Options for California's Energy and Economic Future

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Abstract: This study estimates the fiscal, energy, and environmental tradeoffs involved in supplying California's future energy needs. An integrated framework is developed whereby an econometric forecasting system of California energy demand is coupled with engineering-economic models of energy supply, and economic impacts are estimated using input-output models of the California economy. A baseline scenario in which California relies on imported electricity to meet future demand is then compared against various energy supply development scenarios over the forecast horizon (2012–2035). The results indicate that if California implements its renewable portfolio standard (RPS), there will be a substantial net cost in terms of value added, employment, and state tax revenues because the economic benefits of building capacity are outweighed by higher energy prices. Although carbon emissions fall, the cost per ton of avoided emissions is well above market prices. Building out natural gas fired generation capacity also leads to losses compared to the baseline, although the impacts are relatively minor. Meanwhile, a strategy of replacing imported crude oil and natural gas with domestic production using indigenous resources increases gross state product, employment, and tax revenues, with minimal impact on carbon emissions. This option could, therefore, help mitigate the costs of California meeting its RPS commitment.

Keywords: electricity; renewables; natural gas; oil; input-output; employment; carbon

1. Introduction

More than twenty-five states have adopted renewable energy portfolio standards in the belief that wind, solar, and other renewable forms of energy will create jobs, reduce greenhouse gas emissions, and reduce reliance on imported energy. At the same time, the development of oil and natural gas resources in shale formations is stimulating output, employment, and tax revenues in several states, including North Dakota, Texas, Pennsylvania, and Louisiana. Development of offshore oil and natural gas resources would have similar effects. The benefits of renewable and fossil fuel energy are widely touted by their respective proponents. What is not known, however, is the comparative magnitude of the economic and environmental impacts of these two paths for energy development. The aim of this paper is to perform an analysis that quantifies these impacts.

The development of renewable and non-renewable resources need not be mutually exclusive. Brazil, with its significant biofuels industry and rapidly developing offshore oil industry, illustrates that producing renewable energy need not preclude the possibility of expanding oil and natural gas production. Could developing both renewable and fossil fuel energy serve the best interests of society to ensure economic growth, job creation, fiscal balance, and environmental quality? This study attempts to shed light on this question with an analysis of California's energy future.

California represents a compelling case study for addressing this question. With passage of the California Renewable Energy Resources Act (Senate Bill X 1-2), California is seeking to supply a third of its retail electricity sales from renewable energy by 2020. This goal will require the construction of a large number of renewable energy facilities that will directly generate a significant number of construction jobs and indirectly stimulate many support industries that provide goods and services for the construction and operation of these plants. If these renewable energy goals are not achieved, the most likely alternative to be adopted is natural gas-based electricity generation. Currently, natural gas plants are the most frequent choice for new power in California.

Meanwhile, California has the largest untapped potential (outside Alaska) for additional oil and gas production in the United States. Humphries *et al.* [1] report that offshore California contains more than 10 billion barrels of oil and nearly 12 trillion cubic feet of natural gas. Onshore, the Monterey Shale may contain more than 15 billion barrels of oil. At current market prices, these reserves are worth more than $2 trillion. As an illustrative example, this study estimates the impacts of developing a subset of these resources: the crude oil and natural gas reserves under the Santa Barbara Channel. Developing additional oil and gas production in California would create jobs and significant royalty and tax revenues for the state. From an environmental perspective, an expansion of oil and gas production in California would be carbon neutral in the respect that it simply displaces imported fuels.

Therefore, expanding renewable or fossil fuel production or some combination thereof could be an attractive possibility for California. The objective of this study is to estimate the economic, energy, and environmental impacts of the two alternative electricity generation options (renewable or natural gas development) and the option of expanded production of domestic fossil fuel resources.

California's interests in electricity generation and oil and gas development are related (and thus we compare these particular policies) in three ways. First, each of these policies is concerned with the supply of energy to California and may indeed be part of the same energy supply portfolio in future years. Second, each policy would help California to become more energy self-sufficient. In 2009, 54% of the total supply of energy to California came from imported oil and natural gas, and 13% from imported electricity. Building out domestic energy production can help to reduce this dependency on out-of-state energy resources. Third, producing additional crude oil either offshore from the Santa Barbara Channel or onshore from the Monterey Shale would produce significant amounts of associated natural gas that could be used to generate electricity. Nonetheless, a side-by-side comparison of electricity generation strategies and oil and gas development should not be interpreted as showing that one policy should be undertaken instead of the other, since they are different energy supply policies that are not mutually exclusive.

As the focus of this study is on energy supply, we do not analyze demand-side energy initiatives such as electric vehicle proliferation or tightened California Air Resources Board regulations on vehicle emissions. In addition, the oil and gas production scenario might be compared with other policies designed to raise tax revenues, such as increasing personal or corporate income rates and real estate taxes, which deserve separate study.

To consider these energy supply pathways, this study uses a two stage integrated modeling framework. The first modeling stage is an econometric forecasting system of California energy demand coupled with engineering-economic models of energy supply. The first stage model is very similar to that used by Considine and McLaren [2]. The second stage uses the output from the California energy model to estimate the impacts of energy technology choices on output, employment, and tax revenues. The Jobs and Economic Development Impact (JEDI) models for California developed by the National Renewable Energy Laboratory [3] provide estimates of the economic impacts of the electricity generation scenarios. Since the JEDI models are based upon input-output tables from Minnesota IMPLAN Group (MIG), Inc. [4], the IMPLAN model is used to estimate the economic impacts of developing oil and natural gas resources.

The next section presents the modeling framework in detail. Section 3 then develops the energy supply scenarios, and Section 4 presents and discusses the results. Finally, Section 5 concludes the paper.

2. Modeling California's Energy and Economic Future

Some people view California's energy sector as a blueprint for how America should be powered in the future. The Golden State leads the nation in non-hydroelectric renewable energy production. California has also achieved considerable improvements in energy efficiency, allowing its economy to grow with proportionately less energy use over time. Despite this, California is the second largest energy consuming state in the nation behind Texas and will continue to require more energy with economic and population growth. In addition, California is increasingly dependent on energy sources outside its borders, especial fossil fuels. In 1970 California produced 67% of its energy, yet by 2009 the state imported 67% of its energy needs. How much energy will be needed in the future, where it could come from, and at what cost to society are the central questions of this study.

This study produces projections of future energy consumption by sector in the California economy from 2010 to 2035 given assumptions on primary fuel prices, economic growth, and population growth. The econometric equations include time trends to capture the effects of technological innovations and energy efficiency standards on energy consumption above and beyond those impacts emanating from changes in relative energy prices, income, or business activity. Electricity costs and rates are based upon assumptions for fuel prices and capital costs associated with each electricity technology scenario. Capital expenditures to build generation capacity under each scenario are also estimated. As new electricity production capacity goes into operation, the costs are passed through to consumers in the form of higher electricity rates that then affect the demand for electric power. For example, in the two scenarios that involve building out renewable or natural gas capacity, electricity rates increase as these sources of more expensive energy replace cheaper imported electricity. These higher rates reduce households' discretionary income and businesses' profits, in effect acting like a tax increase that reduces income, employment, and tax revenues. On the other hand, building and operating these facilities stimulate the economy. The key question is whether the stimulus from investments in either renewable or natural gas generation capacity offsets the negative effects of the higher energy prices needed for recovery of the investment and operating costs of these facilities.

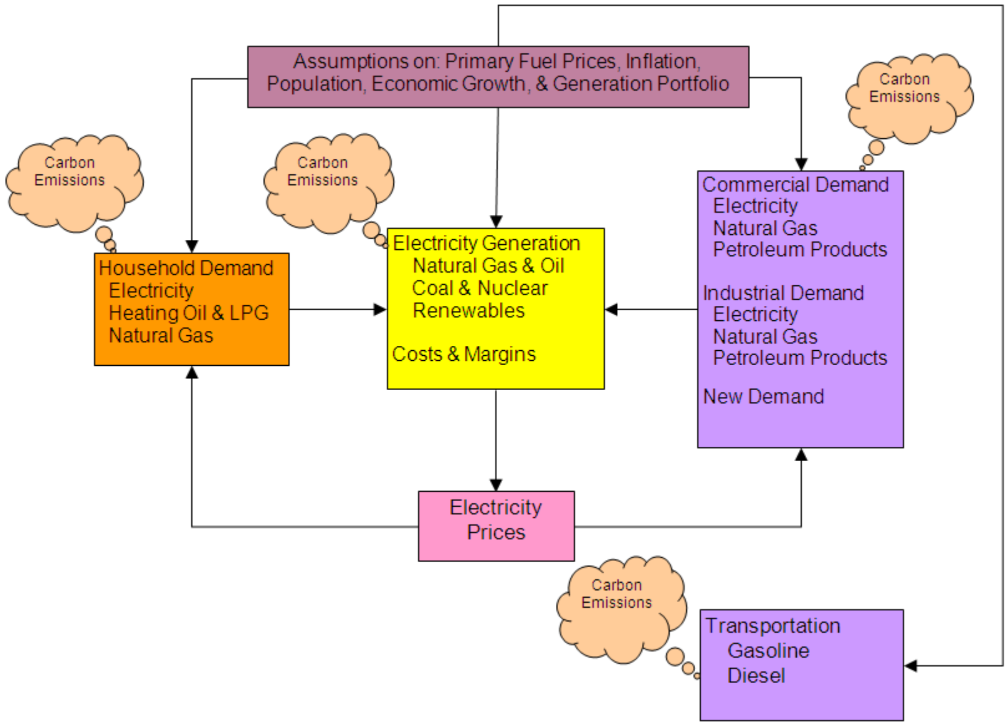
The next two subsections describe the two modeling stages used in this study to address this question. The two modeling approaches provide the economic, energy, and environment tools of analysis, and are used in a sequential or recursive fashion to clearly delineate the gains and losses associated with each scenario.

2.1. The Energy Market Forecasting Model

The energy-forecasting framework is built from two different perspectives. First, the end-use demand for fuels in the residential, commercial, and industrial sectors are modeled from an economic perspective in which energy demand is a function of relative prices, population, and the level of economic activity. On the supply-side for electricity, however, an engineering-economic perspective is adopted in which capacity, utilization rates, and heat rates are specified exogenously. Imports of electricity are determined endogenously as the difference between demand and electricity generation within California. Hence, imports of electricity are modeled as the swing fuel, which is consistent with the recent past in California.

A schematic of the line of causality between the assumptions and the endogenous variables is presented below in Figure 1. The forecasting model determines energy consumption—including electricity demand, generation, and prices—given exogenous assumptions for primary fuel prices; economic growth, inflation, and electricity capacity expansion plans. End-use electricity demands and net electricity exports determine electric power generation requirements, which then drive the consumption of fuels in power generation. Generation capacity, operating rates, and heat rates of operating units determine the composition of fuel consumption by electric utilities and the average cost of electricity generation. Retail electricity prices are calculated by adding transmission and distribution charges to average generation costs.

Figure 1. Energy model overview.



As Figure 1 illustrates, carbon emissions are tracked for each sector of the economy. The carbon tracking provides a nearly complete account of carbon dioxide emissions in California. Carbon emissions, therefore, are endogenous and depend upon energy prices and economic activity driving energy demand and the choice of electricity generation capacity. The feedback of final electricity demand on the demand for fuels and end-use electricity prices allows an integrated evaluation of electricity demand and fuel choice in power generation.

There are five main components of the energy model. The first three include systems of energy demand equations for the residential, commercial, and industrial sectors. The fourth involves the demand for transportation fuels, including gasoline and diesel fuel. The fifth and final component involves the electricity generation sector. A list of the endogenous variables in the energy model appears in Table 1. The energy demand equations for each sector consist of a cost share system and an aggregate energy quantity equation. The quantities are derived by multiplying energy expenditures, which equal the divisia price index multiplied by the corresponding quantity index, by the respective cost share and then dividing by the appropriate price. The model is programmed using the econometric software package Time Series Processor (TSP) 5.1 from Stanford University. The supplementary material details the formulation of the energy demand models and the econometric results from their estimation. The results indicate that all own-price elasticities are negative and, therefore, consistent with economic theory. The own-price elasticity of demand for electricity is very price inelastic, which is consistent with findings in many other parts of the world. Estimated energy demand fits the observed data well, and the diagnostic tests support the model specifications. Overall, the results seem to be very reasonable.

Table 1. Model endogenous variables and identities.

Endogenous Variables	Type	Endogenous Variables	Type
Residential Sector		*Commercial Sector*	
Divisia energy price	I	Divisia energy price	I
Aggregate energy quantity	B	Aggregate energy quantity	B
Cost shares & quantities		Cost shares & quantities	
Natural Gas	B	Natural Gas	B
Liquid Propane Gas, *etc.*	B	Petroleum Products	B
Electricity	B	Electricity	B
Electricity Generation		*Industrial Sector*	
Generation & Fuel Use		Divisia energy price	I
Natural Gas	B	Aggregate energy quantity	B
Nuclear	B	Cost shares & quantities	
Coal	B	Boiler & Process Fuels	B
Hydroelectric	B	Natural Gas	B
Other Renewables	B	Coal	B
Electric power generation	I	Other petroleum products	B
Electricity consumption	I	Electricity	B
Average Generation Costs	I	*Transportation*	
Retail Electricity prices	B	Gasoline in road travel	B
		Diesel in road travel	B

Notes: I = Identity or mathematical equality, B= Behavioral econometric equations.

2.2. Economic Impact Analysis and Models

The three energy supply scenarios under investigation in this study all involve significant capital investments either to build renewable energy plants, natural gas power generation stations, or oil and gas production facilities. These capital investments generate an array of direct, indirect, and induced impacts on the California economy. Once construction is complete, these facilities go into operation, which further stimulates the local economy.

Expenditures at all stages of production generate *indirect economic impacts* as the initial stimulus from expenditures on energy development is spent and re-spent in other business sectors of the economy. For example, in developing mineral leases oil and gas drilling companies employ the services of land management companies that in turn purchase goods and services from other businesses. In turn, the wages earned by these employees increase household incomes, which then stimulates spending on local goods and services. These impacts associated with household spending are called *induced economic impacts*. The total economic impacts are the sum of the direct, indirect, and induced spending, set off from the investment spending to develop energy projects.

This paper estimates these total economic impacts measured in terms of value added, tax revenues, and employment, by performing a regional economic impact analysis using input-output models. Input-output models track transactions between various sectors of the economy and provide a means for estimating how spending in one sector affects other sectors of the economy. IO tables are available from MIG, Inc. [4] (formerly Minnesota IMPLAN Group), based upon data from the Bureau of

Economic Analysis of the U.S. Department of Commerce. This project uses these tables to estimate the economic impacts from our estimates for the construction and operation of energy production facilities.

Following the estimation of the energy demand model, this study estimates the economic impacts of the alternative electricity technology scenarios using the JEDI program developed by the National Renewable Energy Laboratory [3]. Spending levels are based upon the costs of new electricity capacity and generation from the energy demand model. The economic impacts from JEDI are estimated based upon multipliers derived from IMPLAN. Accordingly, the economic impacts of Santa Barbara oil and natural gas development are also estimated using the IMPLAN model for California, based upon estimates of the direct employment requirements for construction and operation of these facilities. Employment data from Santa Barbara development are obtained from Schniepp [5]. IMPLAN is widely used to estimate the economic impact of new energy production but a side-by-side comparison of three energy supply technologies is unique.

Several studies estimate the impacts associated with the adoption of renewable energy performance standards. In the case of California, an early report by the California Public Utilities Commission by Hamrin *et al.* [6] found that a 33% renewable portfolio standard (RPS) would provide a net saving to California's electricity consumers over a twenty-year period (2011–2030). In this case, the 33% RPS would have a positive economic impact, even without considering the fiscal benefits of building and operating new renewable capacity. Similarly, Roland-Holst [7] used the Berkeley Energy and Resources (BEAR) computable general equilibrium (CGE) model to find that an aggressive RPS, along with incentives and standards to promote energy efficiency, would help protect California from higher fossil fuel prices and, thereby, promote economic growth.

Findings across the wider literature, however, indicate that renewable standards increase energy prices. In a review of 31 studies of state or utility-level RPS cost impact analyses in the U.S. completed since 1998, Chen *et al.* [8] find that only six project lower retail electricity rates. Studies that predict cost increases find they are typically modest, with only 10 studies predicting rate increases above 1% (and just two studies predicting rate increases of more than 5%). Chen *et al.* [8] also find that, of the studies that evaluate macroeconomic impacts, 11 out of 12 predict some level of net employment gain to RPS policies. The magnitude of the impact, however, varies widely and appears to largely depend on the assumptions of the studies rather than on the amount of incremental renewable generation required. Overall, Chen *et al.* [8] argue that there is considerable room for improvement in the analytical methods of the studies considered. More recently, Fischer [9] finds that electricity rates can decrease at low RPS shares from lower natural gas prices but that electricity prices increase sharply as RPS shares increase.

Studies that incorporate fiscal impacts of expanding the renewable generation base, alongside the impacts on energy prices, include a series of studies by the Beacon Hill Institute at Suffolk University. These studies evaluate the impact of renewable standards in Montana, Colorado, and Oregon using the STAMP (State Tax Analysis Modeling Program) CGE model (Tuerck *et al.* [10–12]). In each case, the results indicate that the RPS will increase electricity costs, and in turn lead to a significant net loss in jobs, wages and income. This net employment loss includes jobs that would be created to build out renewable electricity power plants.

Dismukes [13] estimates the impact of New Jersey's RPS (20% renewables by 2020) on the cost of electricity relative to a baseline of fossil fuel generation (coal and natural gas). He then uses IMPLAN to analyze the total net economic impacts from the proposed changes in rates and the investment in renewable technologies. The results suggest that the RPS leads to significantly higher electricity rates and that these costs outweigh the benefits of building and operating the renewable energy plants under the RPS.

For this study, under each energy supply technology scenario, there are economic benefits from constructing and operating new electrical generation capacity. However, the renewable and natural gas scenarios raise electricity rates, as they effectively replace relatively cheap imports with more expensive domestically produced energy. Studies of oil price shocks suggest that higher energy prices reduce consumption and employment (Davis and Haltiwanger [14]; Edelstein and Kilian [15]). Hence, this study models the impacts of higher energy expenditures as a tax increase for households. The aggregate increase in household utility costs relative to the baseline scenario (reliance on electricity imports) is estimated from the energy model and then disaggregated by income class. Household incomes are then reduced by these amounts and the IMPLAN model is solved to estimate the induced impacts of these higher household energy expenditures.

Unlike the household sector, the broad aggregates of commercial, industrial, and transportation energy demand cannot be disaggregated to the more than 400 sectors in the IMPLAN model. Accordingly, for each of these three sectors the impacts of higher energy prices are estimated by multiplying the increases in energy expenditures by value added multipliers from IMPLAN. These multipliers are calculated as weighted averages across the commercial, industrial, and transport sectors. The results indicate that these multipliers, which equal the ratio of direct, indirect, and induced impacts relative to the direct impact, are 1.79, 2.79, and 2.46 for the commercial, industrial, and transport sectors respectively.

For the renewable or natural gas scenarios, estimates of the total MW in operation in each year are obtained from the energy demand-forecasting model. From this we derive the total capacity construction requirements, where the construction period for renewable and natural gas power plant projects is assumed to be three years (This assumption does not affect the overall estimated economic impacts from construction as they are determined by overnight costs. It will only have some bearing on the distribution of the construction impacts over the forecast horizon). This information is then entered into each JEDI model for California. Fully calibrating the project descriptive data in JEDI with that used in the energy demand model, including capacity utilization rates, installation costs, and operation and maintenance costs data for each generation technology, the JEDI models are then solved to obtain estimated job and gross output impacts in each year. At the time of this study, there is no JEDI model available for biomass electric power generation plants. Hence in this case we follow the assumption by Kammen *et al.* [16] that a biomass energy facility would be similar to a coal-fired power plant, and use the JEDI model for coal. Although this assumption is not ideal, these plants are structurally similar and it will not affect the central results of this paper since the build out of biomass is relatively very small. For the construction impacts, JEDI computes the total economic impacts of building the entire project. However, since only a proportion of the project is built in each year, these total impacts are converted into average annualized impacts during the construction period of the project.

The employment multiplier, which is an average across all sectors of the economy, is derived implicitly from the estimated impacts returned by the input-output models. In particular, the JEDI results for the renewable scenario indicate that there are on average 5.6 jobs per million dollars of gross output. The same employment multiplier is implicit to the natural gas impacts returned by JEDI. Multipliers derived directly from IMPLAN indicate that the value added to gross output ratio is 0.51 (based on a weighted average). Hence this study uses an average value of 11 jobs per million dollars of value added for the renewable portfolio standard and natural gas scenarios. Meanwhile, the IMPLAN results indicate that there are 4.5 jobs per million dollars of value added for oil and gas development.

The job estimates obtained in this paper are in line with those obtained elsewhere in the literature. For example, Wei *et al.* [17] examine the direct employment impacts of renewables estimated by 15 recent studies. Our direct job estimates, in terms of job-years per MW of nameplate capacity constructed and installed, and jobs per MW of nameplate capacity in operation, are generally within the ranges found by Wei *et al.* [17] for solar thermal, PV, biomass and geothermal. We find at the beginning of the forecast horizon that direct construction and installation jobs (job-years/MW) are 5.92, 9.44, 0.68, 5.70, and 6.93 for solar thermal, PV, wind, geothermal and biomass respectively. Direct operation jobs (jobs/MW) at this time are 0.35, 0.15, 0.06, 0.25 and 0.14 for solar thermal, PV, wind, geothermal and biomass respectively. Our direct job estimates for onshore wind are not directly comparable to those in Wei *et al.* [17], whose estimates combine onshore and offshore wind. However, our total (direct, indirect and induced) construction job estimates for wind are slightly above those impacts found by Slattery *et al.* [18] for onshore wind in Texas. This difference is likely to arise because Slattery *et al.* [18] use project-specific installation cost data that is lower than the average nationwide installation cost data.

For each scenario, the loss in jobs and value added due to higher energy expenditures is subtracted from the gain in jobs and value added due to the construction and operation of new capacity. This allows an estimate of the net impact on jobs and value added for each year over the forecast horizon. The net impact on state tax revenues over the forecast horizon is computed in the same way. In the renewable scenario there is an additional loss of state revenues due to subsidy payments made to renewable power generation of 2.2 cents per kilowatt-hour over the plant's first ten years of service. This broadly reflects prevailing policy.

3. Scenario Development

This study uses the energy demand-forecasting model discussed in subsection 2.1 to project future energy consumption by sector in the California economy from 2010 to 2035, given assumptions on primary fuel prices, economic growth, and population. The U.S. Energy Information Administration (EIA) adopts the same time frame in the Annual Energy Outlook. The full econometric model, including the behavioral equations, the cost, generation, and retail rate equations for the electric power sector, and the carbon accounting relations, involves the simultaneous solution of 133 equations. Simulations are performed using TSP 5.1 Gauss-Newton algorithm.

A baseline or business-as-usual projection, which assumes that any excess electricity demand beyond the forecast capacity base is met by imports, is used as the basis of comparison to evaluate the energy, environmental, and economic impacts of the following three related energy supply scenarios:

- Full implementation of California Renewable Energy Resources Act;
- Adoption of integrated combined cycle natural gas power generation;

- Development of crude oil and natural gas reserves in the Santa Barbara Channel;

In particular, the following metrics are considered in all three scenarios:

- The level and composition of energy consumption;
- Greenhouse gas emissions;
- Employment;
- Value added;
- Tax revenues.

This comprehensive overview addresses the relative merits and shortcomings of each of these energy technology paths and should be particularly helpful for policymakers. The following passage provides a discussion of the assumptions used to develop each of these scenarios.

This study follows the International Energy Agency's expectations that the recent tightness in oil prices will continue into the future. Specifically, oil prices are assumed to grow at 4.0% in real terms from $68.35 per barrel in 2010. Meanwhile, natural gas prices follow the latest EIA forecast (from the Annual Energy Outlook [19]) of 1.9% average real growth from $4.16 per thousand cubic feet in 2010. Finally, coal prices grow at 1.0% in real terms from $2.19 per ton in 2010 (also in line with EIA forecasts).

For economic growth, this study considers an historic (high) growth path and a low growth path. For the historic growth path, the average growth trends displayed over the 1970–2009 period in California continue until 2035. Hence, inflation is 4.0%, real value added in the commercial and industrial sectors grow at 3.7% and 3.0% respectively, and real personal disposable income grows at 3.7%. For the low growth path, high budget deficits and increasing fuel prices take a toll on the future growth performance of the California economy. In this case we take the average growth trends displayed over 2000-2009. Under this scenario, inflation grows at 1.8%, real value added in the commercial and industrial sectors grow at 2.4% and 1.3% respectively, and real personal disposable income grows at 2.7%. In both scenarios this study assumes the population grows at the 1% per annum, which is consistent with U.S. Census forecasts.

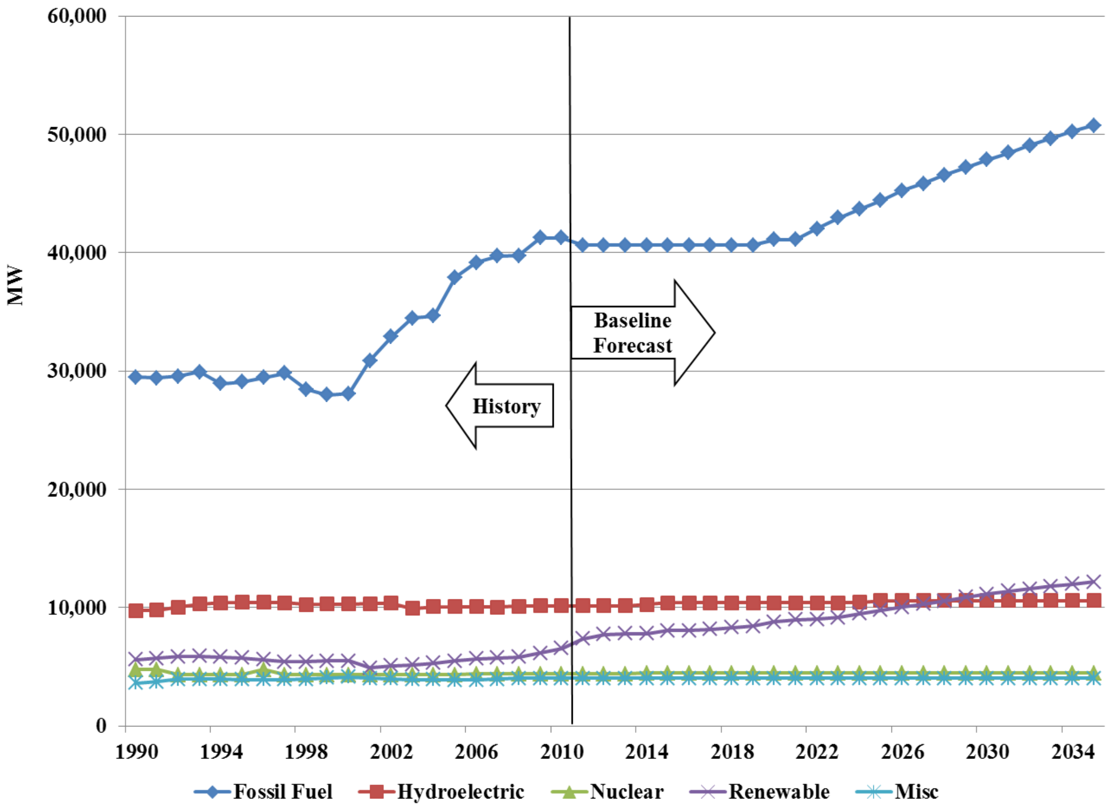
Electricity demand, generation costs, and retail rates under each of the scenarios are simulated using the econometric model based upon estimates of the costs of installing and operating these generation technologies, which are known as levelized costs. Levelized costs are defined as the variable costs of operation plus a capital cost recovery component, which are the amortized capital costs of installation. This study assumes a 6.8% real weighted average cost of capital in the computation of the capital recovery factor. This is the discount rate used by the EIA in the 2012 Annual Energy Outlook. Operating and capital costs are estimated for a base year using EIA data from the 2012 Annual Energy Outlook and then projected into the future based upon the EIA's forecasts of future generation costs. The overnight cost data for geothermal generation reported by the EIA essentially represents the lowest cost site that could be built in the "best" region (Northwest Power Pool region, where most of the proposed sites are located). We therefore take our overnight cost data for geothermal from the JEDI default values calculated by the National Renewable Energy Laboratory, which should be a more representative average.

3.1. Baseline Scenario

In the baseline (business-as-usual) scenario, the model is constructed such that electricity demand requirements in excess of the forecast generation capacity are met by imports. These imports currently are supplied by a combination of coal (47%), natural gas (20%), hydroelectric (23%), and nuclear resources (10%). Marginal generation costs for hydroelectric and nuclear resources are assumed to remain constant in real terms. For coal and natural gas, real marginal generation costs increase at 0.6% and 1.6% respectively from 2011 to 2035. The weighted average cost of imported electricity rises at 0.5% in real terms from 2011 to 2035. If electricity imports beyond 2008 levels are required during the forecast period, this study assumes that these imports are produced entirely by new natural gas capacity built outside California. The assumption that all new electricity imports are natural gas reflects the national trend (since 1995, 80% of new capacity in the U.S. has been gas-fired units). Hence, if California electricity imports exceed the peak levels of 2008, the price of electricity imports rises to reflect the incremental cost of building new capacity.

The baseline forecast also requires projections of available electricity generation capacity. This study assumes that baseline generation capacity by type in California grows at the same rate as the 2011 western regional forecasts published by EIA. These forecasts indicate an increase in renewable energy capacity from roughly 6,500 MW in 2010 to over 12,000 MW by 2035 (see Figure 2). Hydroelectric and nuclear capacity is expected to remain unchanged. Fossil fuel based capacity, which is overwhelmingly natural gas, is expected to remain at current levels through 2020 and then increase after that time to 2035 (see Figure 2).

Figure 2. Projected baseline electricity generation capacity.



The projected baseline electricity capacity forecast includes planned builds and construction in progress in California, and reflects both new capacity and retirements of existing capacity. This build out of capacity also takes place in the RPS and natural gas alternative scenarios. However, as we are reporting the impacts of these scenarios relative to the baseline, impacts from the building out and retirement of this capacity are effectively being netted out of the analysis and as such are modeled implicitly. In the RPS and natural gas scenarios there is an additional build out of renewables and natural gas capacity, respectively, over and above the baseline build out. We are assuming there are no power plant retirements of this new capacity over our forecast horizon since it is all newly built.

3.2. California Renewable Energy Resources Act

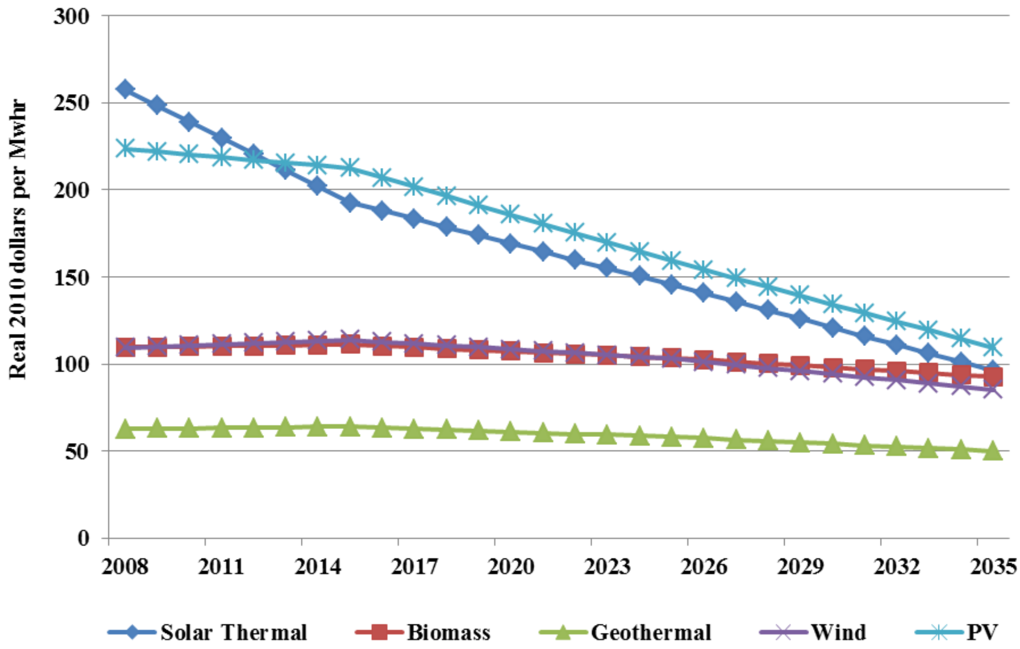
The California Renewable Energy Resources Act (Senate Bill X 1-2) is one of the most ambitious renewable portfolio standards (RPS) in the country. The law requires 33% of electricity retail sales to be served by renewable energy resources by 2020. (Hawaii technically has the most ambitious RPS mandate, with a target of 40% by 2030). The standard applies to all electricity retailers in the state, including publicly owned utilities (POUs), investor-owned utilities (IOUs), electricity service providers and community choice aggregators. Under the RPS compliance schedule, these entities are required to achieve 33% of retail sales from renewables by 2020.

A wide range of technologies qualify for California's RPS. This scenario considers an expansion of California's current procurement path (44% onshore wind, 24% solar thermal, 15% geothermal, 10% PV and 7% biomass) to achieve the 33% renewable target by 2020. Beyond 2020, this scenario assumes that California continues an aggressive development path for renewable energy, reaching 40% of total retail sales by the end of the forecast period. SB X 1-2 generally favors in-state development, but does allow for some importation of out-of-state renewables. In order to represent this feature within our model, this study allows 10% of the RPS target to be met by out-of-state wind generation.

The levelized costs of the renewable technologies appear below in Figure 3. Costs for solar thermal and photovoltaic (PV) costs are substantially higher than the other generation technologies. Costs of solar are highly sensitive to its operating rate. Sandia National Laboratories [20] reports that without energy storage, the annual capacity factor of any solar technology is generally limited to about 25%. Therefore, this study assumes that solar thermal and PV plants operate at a 25% capacity utilization rate. The EIA [21] also reports that the capacity utilization of PV systems in California is 25%. If the solar operating rates could be increased further, this would dramatically reduce the cost of solar generated electricity. Meanwhile, the capacity utilization rate for wind is 25% which reflects the realized rate in California in 2010 rather than an estimated value (following Boccard [22]), and the rates for geothermal (91%) and biomass (83%) reflect EIA estimates from the 2012 Annual Energy Outlook.

The levelized costs of the solar technologies change in rough proportion to the estimated change in the overnight capital costs of generation capacity because there are no fuel costs and relatively small operating and maintenance costs. Hence, the progress this study forecasts will be made in bringing down solar generation costs reflects the substantial fall in overnight capital costs for solar technology projected by the EIA. By 2035, solar thermal technology is cost competitive with the traditional energy generation sources.

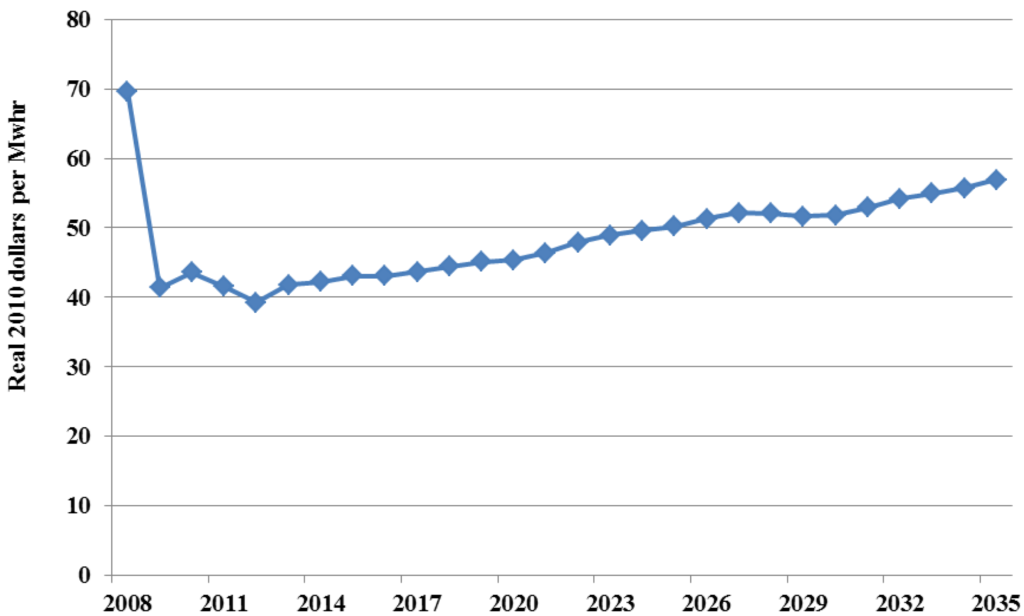
Figure 3. Levelized costs of renewable generation capacity.



3.3. Natural Gas Based Electricity Generation

Rather than using renewable energy to supply new electricity requirements, natural gas-based generation could be used to supply those needs. Hence, this study considers the costs and environmental trade-offs of replacing all new renewable generation under the RPS scenario from now to the year 2035 with combined cycle natural gas generation. Over recent years, natural gas plants have been the most frequent choice for new power in California. The projected levelized costs for new natural gas combined cycle capacity are displayed below in Figure 4.

Figure 4. Levelized costs of new natural gas generation capacity.



The EIA reports that the high end of the likely utilization range for this technology is slightly below 90%, and so in this paper we assume a capacity utilization rate of 78%. Costs for new natural gas generation technology fall markedly in 2009 due to a large decline in natural gas prices, before costs gradually increase as natural gas prices recover, as predicted by the 2012 EIA forecast [19].

3.4. Developing Oil and Natural Gas Resources

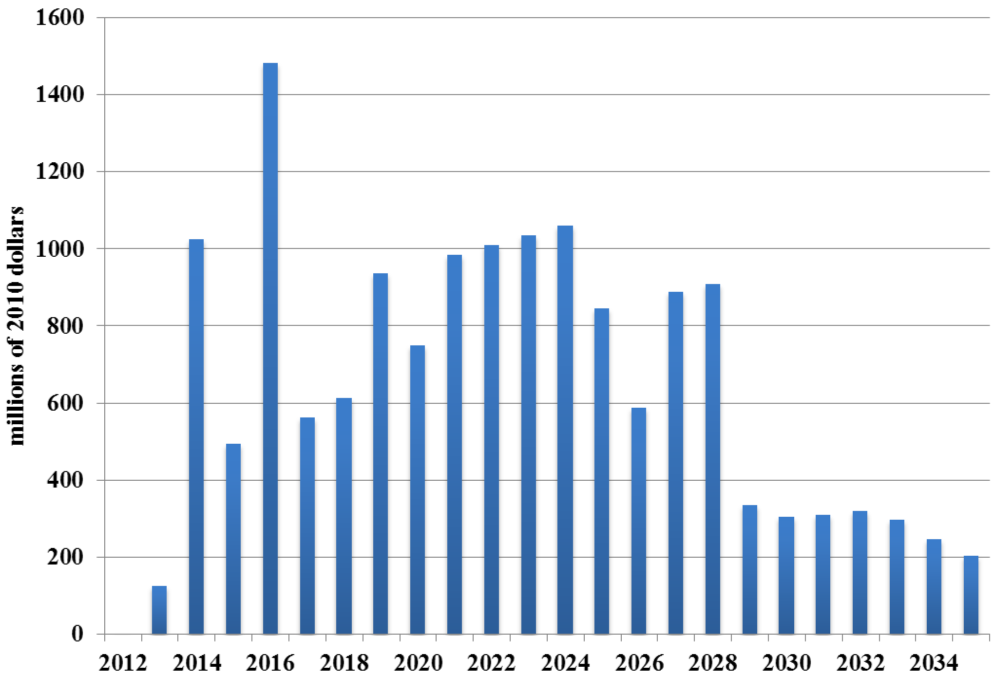
The third and final scenario examined in this study involves additional development of crude oil and natural gas under the Santa Barbara Channel. This field has been under development for many years, but environmental concerns led to a permanent moratorium in California on new offshore oil and gas leasing and development in state waters. The California Lands Commission halted additional leasing of state offshore tracts after the Santa Barbara oil spill in 1969. In 1994 the California legislature codified the ban on new leases by passing the California Coastal Sanctuary Act that prohibited new oil and gas leasing in state waters from Mexico to the Oregon border. Federal leasing has been deferred, with temporary moratoria in place for the past 28 years. In 1990 President G.H. Bush issued an executive moratorium banning new federal leasing through the year 2000 in many areas of the U.S. including California. In 1998, President W.J. Clinton extended the moratorium through 2012. In July 2008, President G.W. Bush rescinded this executive order. No new leasing will occur in state offshore waters unless the legislature acts to eliminate or modify the prohibition. The State Land Commission is prohibited from issuing new leases unless it determines that oil and gas resources are being drained from wells in federal waters. The prohibition also may be modified under a severe energy supply disruption or if the new leases are found to be in the best interest of the state. Development may still occur on state and federal leases granted prior to the moratorium. Currently, there are 82,000 acres under lease within the Santa Barbara Channel.

Recent technological advances now allow environmentally safe extraction of Santa Barbara's oil and natural gas resources. For example, extended reach drilling can extract offshore oil from land without the need for new offshore platforms, minimizing the threat of oil spills in coastal environments. Extended reach drilling is similar to the methods used in shale drilling. For an analysis of the environmental regulatory performance of these activities see the recent study by Considine *et al.* [23]. Moreover, increasing California's oil and gas production would reduce the need for crude oil imports, reducing air emissions associated with oil tanker traffic. This study calculates this carbon emission offset by using the CO_2 efficiency formula provided by the International Maritime Organization [24]. This formula allows computation of the total CO_2 emissions produced by crude oil tankers for a given amount of ton-kilometers of work done. This study assumes the displaced oil imports would be coming from Valdez, Alaska, and delivered to Long Beach, California, in crude oil tankers with an average cargo capacity of 150,000 tons.

While developing California's oil and natural gas resources involves replacing imported energy, prices for petroleum and natural gas paid by California consumers are unlikely to be affected. This is because crude oil prices are determined in world markets and any increase in California production would constitute a small fraction of world production. Likewise, the volumes of natural gas under the development scenario discussed below are quite small relative to U.S. natural gas production. So any additional California crude oil or natural gas production would simply replace imports and not affect prices paid by consumers.

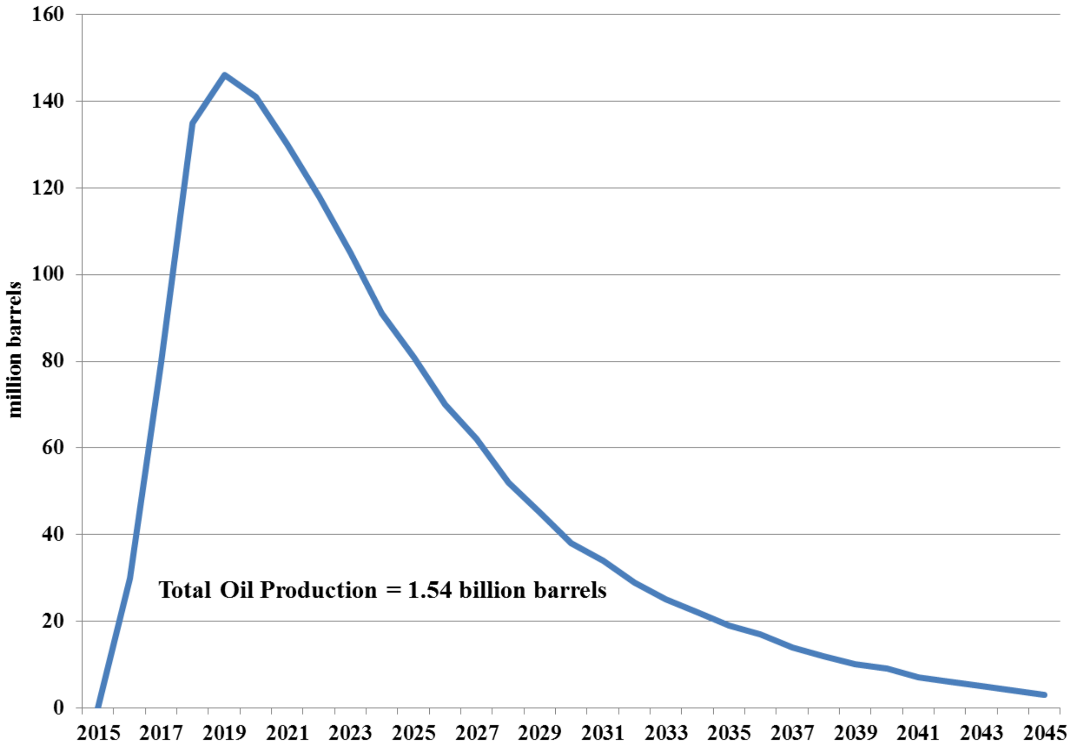
This study considers the construction of onshore facilities for production and transportation of crude oil and natural gas from five new projects and four existing producing areas within the Santa Barbara Channel. Data projections for this development are obtained from Schniepp [5]. The total cost projection for these potential projects is $16.3 billion in 2010 dollars. Costs include exploratory drilling, well construction, processing facilities, water treatment plants and other facilities, and operating expenditures (see Figure 5). These cost estimates also include outlays near the end of the 30-year life of a potential project to abandon the operation.

Figure 5. Total expenditures for new crude oil production from Santa Barbara Channel.



The projected incremental production of crude oil from these investments is displayed below in Figure 6. Production rises sharply during the first four years of potential projects in the Santa Barbara Channel and declines thereafter. Total cumulative production over the 30-year horizon is 1.54 billion barrels of oil and 1.3 trillion cubic feet of natural gas. The estimated economic impact of potential projects in the Santa Barbara Channel will be discussed in the following section.

Figure 6. Possible new crude oil production from Santa Barbara Channel.



4. Energy, Economic, and Environmental Impacts

The baseline (business-as-usual) forecast and the three energy supply scenarios are discussed in each of the four subsections below. For the three scenarios, the energy, economic, and environmental impacts are compared to the baseline forecast. The focus is on five metrics: employment, value added, tax revenues, energy consumption, and environmental emissions.

4.1. The Baseline Forecast

Under the low growth scenario with the average annual increase in gross domestic product of 2.23%, total energy consumption (including consumption of coal, natural gas, and petroleum products in the residential, commercial, and industrial sectors plus consumption of electricity including conversion and transmission losses) grows at 0.71% per annum from 2010 to 2035. Hence, the energy intensity of use (*i.e.*, the ratio of total energy consumption to gross state product) declines on average 1.52% per year. Under the high growth scenario, gross state product increases 3.65% per annum and total energy use increases 1.15% per year. In this case, the energy intensity of use declines 2.49% per annum. These scenarios extend the trend toward greater energy efficiency as illustrated in Figure 7.

As illustrated by Figure 8, natural gas use is projected to expand much faster than petroleum use for an average of 2.23% under the low growth scenario and 2.24% under the high growth scenario. Electricity use follows a similar track expanding 0.67% per annum under the low growth scenario and 1.52% under the high growth scenario. Petroleum use expands at just 0.15% per annum under low growth and 0.97% under high growth. These projections imply that natural gas becomes a greater share of total energy consumption, at the expense of petroleum.

Figure 7. Historical and projected energy intensity of use.

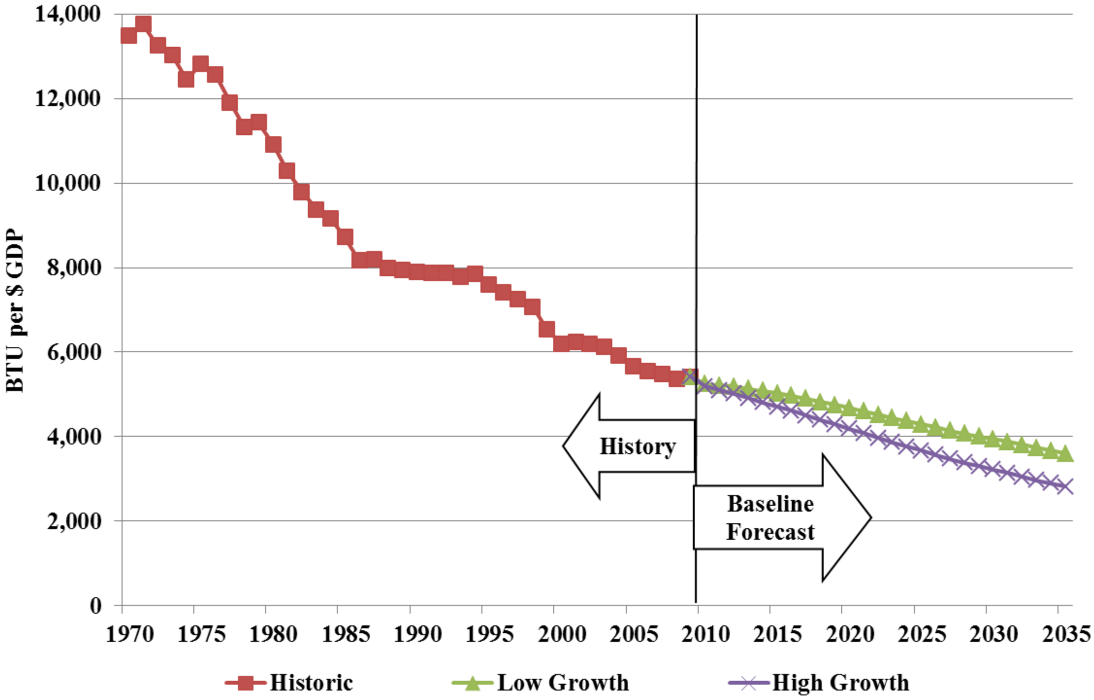


Figure 8. Historical and projected oil, natural gas, and electricity use.

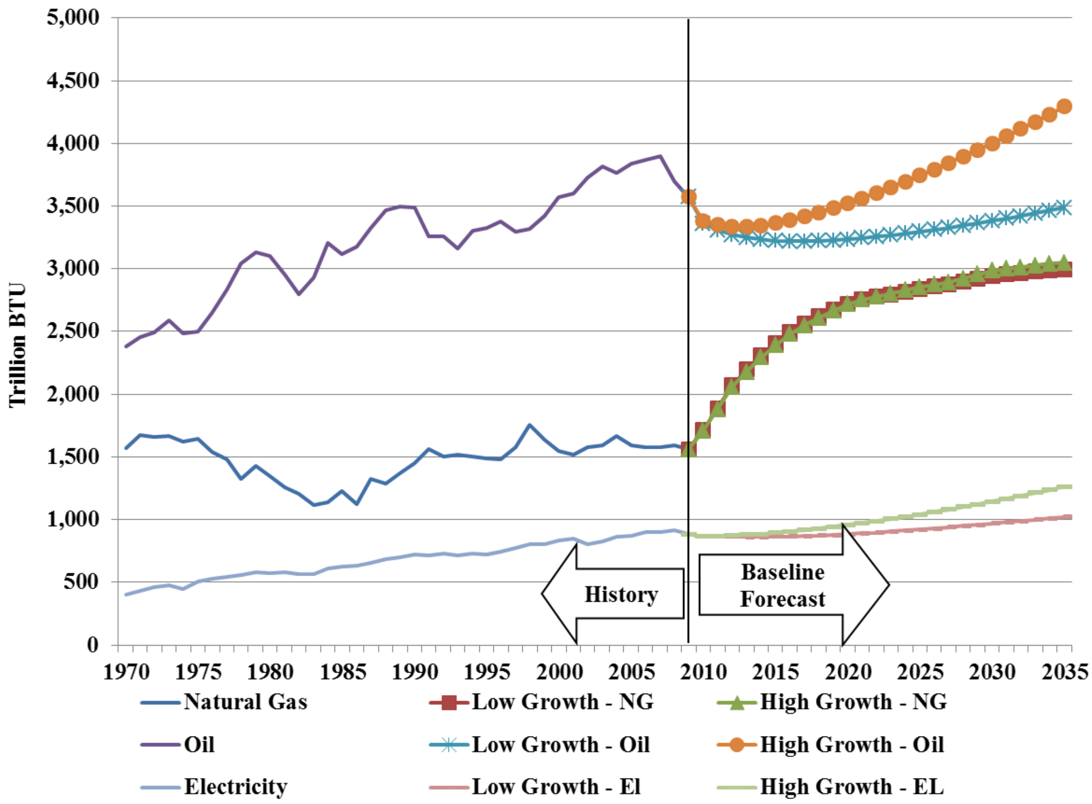
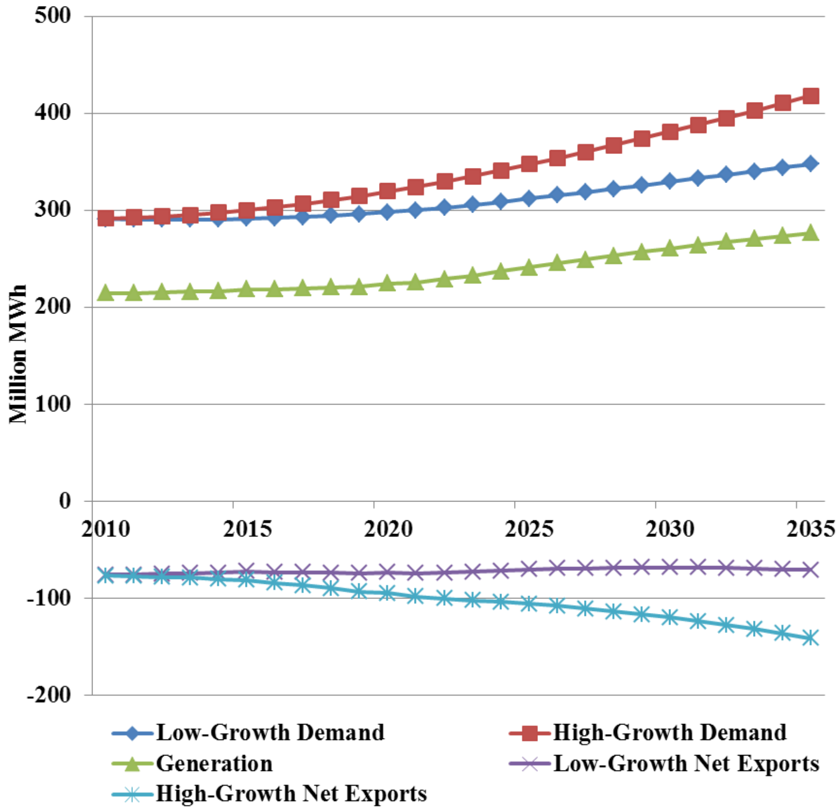


Figure 9 illustrates the trade balance for electricity. Under the low growth scenario, average annual growth in consumption is 0.7% and California requires an additional 57 million MWhr of electricity by 2035. Under the high growth scenario, average annual growth in consumption is 1.4% and California requires an additional 127 million MWhr of electricity by 2035. Under the low growth scenario, net imports of electricity decrease slightly from 76 million MWhr in 2010 to 72 million MWhr in 2035. In contrast, under the high growth scenario, net electricity imports rise to 142 million MWhr in 2035.

Figure 9. Projected electricity demand and imports.



One factor dragging down future electricity demand growth is increasing real rates for electric power. Under the low growth scenario, real generation costs rise from $42/MWhr in 2010 to $50/MWhr in 2035 for a 0.74 percent annual average increase. In contrast, under the high growth scenario, imported electricity prices increase with higher imports, and real generation costs increase at 0.85 percent per year to $53/MWhr in 2035. Retail electricity prices move in tandem with these higher generation costs.

Primarily due to swiftly rising oil prices, real monthly household expenditures on energy rise throughout the forecast period. Figure 10 shows that expenditures increase from $262 per month in 2010 to $437 per month by 2035 under low growth, and from $266 per month in 2010 to $474 per month by 2035 under high growth. In the low growth scenario, residential electricity consumption per customer, which was increasing until the recession in the late 2000s, is essentially flat over the forecast horizon. On the other-hand, under high growth electricity consumption per customer in the residential sector continues an upward trend.

Figure 11 reveals the forecasted future trends in total carbon dioxide emissions. Under low growth, emissions increase from 2010 levels of 429 million tons to 511 million tons by 2035. Under high growth, emissions increase from 2010 levels of 431 million tons to 605 million tons by 2035. These emissions arise from the combustion of natural gas, coal, and petroleum products in the residential, commercial, industrial, and transportation sectors of the California economy, and other states if the electricity is imported.

Figure 10. Real monthly household energy expenditures.

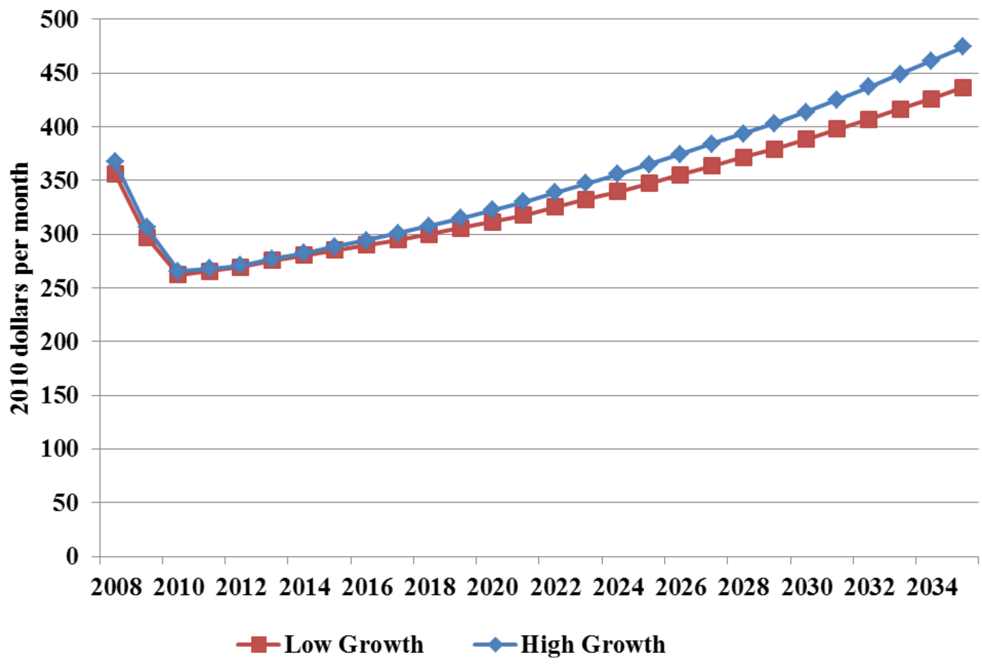
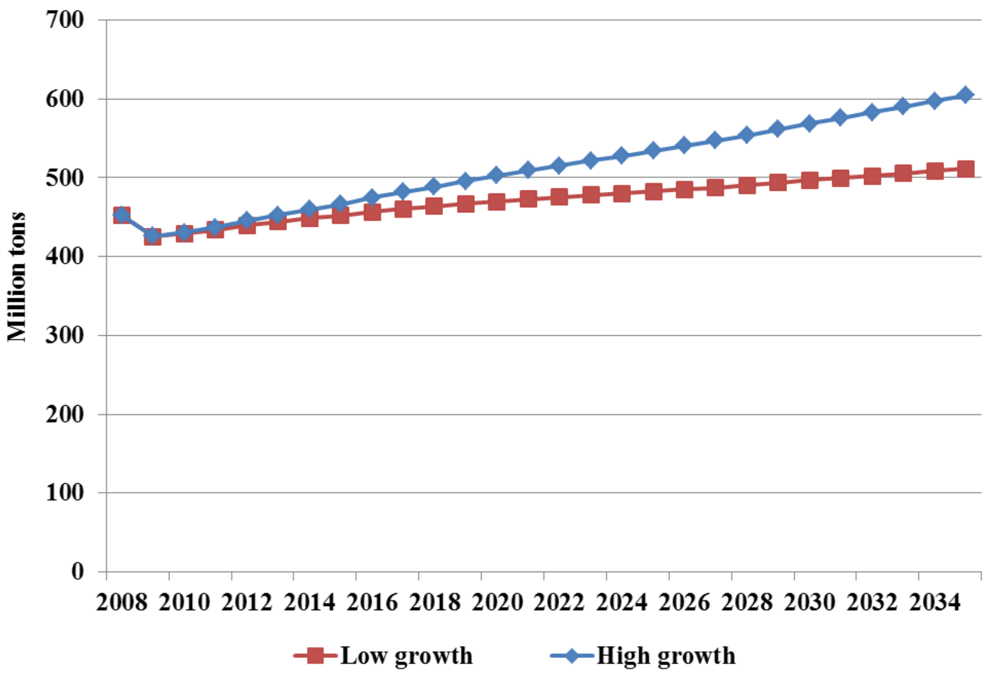


Figure 11. Projected carbon dioxide emissions.



4.2. Impacts of Renewable Portfolio Standard

To achieve the renewable portfolio standard envisioned under the California Renewable Energy Resources Act, a significant amount of renewable electricity production capacity must be constructed. Table 2 shows the new nameplate capacity added of each renewable generation technology in each year. Under the low growth scenario, 3463 MW of new capacity in total is added on average from 2015 to 2020 to meet the 33% RPS standard. Under the high growth scenario, this average increases to 3870 MW of new capacity. Beyond 2020, meeting a 40% RPS goal by 2035 would require an annual average of 432 MW of new annual capacity additions under the low growth scenario and 956 MW under the high growth scenario. The total amount of new nameplate renewable capacity in operation therefore increases from 11,711 MW in 2015 to 27,258 MW by 2035 with low growth, and from 12,400 in 2015 to 37,558 by 2035 with high growth.

Table 2. Renewable energy resources added within California in MW as a result of RPS.

Year	**Low growth scenario**					**High growth scenario**				
	Solar Thermal	**PV**	**Wind**	**Geothermal**	**Biomass**	**Solar Thermal**	**PV**	**Wind**	**Geothermal**	**Biomass**
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	3795	1546	5253	787	330	4018	16	5562	833	350
2016	567	231	785	118	49	649	26	898	135	56
2017	594	242	822	123	52	693	28	960	144	60
2018	613	250	848	127	53	726	29	1005	151	63
2019	633	258	876	131	55	761	31	1054	158	66
2020	531	216	735	110	46	677	27	937	140	59
2021	88	36	121	18	8	204	83	283	42	18
2022	226	92	313	47	20	347	14	480	72	30
2023	208	85	288	43	18	339	13	470	70	30
2024	29	12	41	6	3	164	67	227	34	14
2025	72	29	100	15	6	214	87	296	44	19
2026	92	38	128	19	8	240	98	332	50	21
2027	95	39	131	20	8	252	10	348	52	22
2028	150	61	207	31	13	322	13	446	67	28
2029	63	25	87	13	5	239	97	331	50	21
2030	119	48	165	25	10	302	12	418	63	26
2031	124	50	171	26	11	313	12	433	65	27
2032	187	76	258	39	16	386	15	535	80	34
2033	238	97	329	49	21	458	18	634	95	40
2034	201	82	278	42	17	423	17	586	88	37
2035	210	85	290	43	18	441	18	611	92	38

Figure 12 shows that this build-out of renewable energy capacity requires significant capital outlays. Capital spending peaks at over $16 and $18 billion under the low and high growth scenarios, respectively. The spending for inputs and supplies to operate these plants increases as installed renewable capacity grows but is far less than capital outlays during construction. These capital and operating expenditures generate additional value added and employment in the California economy. Figure 13 below plots the total job gains from building and operating the renewable energy plants required to meet the RPS goals. As explained above, these estimates are obtained by running the RPS scenario through the JEDI model. Under the low growth scenario, the gross employment gains are in the region of 55,000–72,000 jobs per year during the first three years, before averaging 14,000 jobs per year thereafter. The estimated job gains are slightly higher under the high growth scenario at 58,000–78,000 jobs per year in the first three years before averaging 20,000 jobs per year thereafter.

Over the forecast horizon, imports of electricity into California under the RPS scenario decline as increasing amounts of renewable generation come on line. By 2035, electricity imports are just 8 million MWhr under the low growth RPS scenario compared to 72 million MWhr under the low growth baseline scenario. Similarly, electricity imports decline to 55 million MWhr in 2035 under the high growth RPS scenario compared with 141 million MWhr under the high growth baseline scenario.

Meeting the required renewable generation targets increases electricity rates and reduces consumption below the baseline forecasts. Under the low growth scenario, average electricity rates across the residential, commercial, and industrial sectors increase initially over the baseline by 9.6% in 2015 and rise even further to 13.9% over the baseline scenario by 2020. However, as renewables become cheaper over time, the increase in rates declines to 7.1% by the end of the forecast horizon. Electricity consumption falls 1.4% below the baseline in 2015, 2.4% below the baseline by 2020, and by the 2035 is 1.8% below the baseline. The implied own price elasticity of electricity is on average −0.22, reflecting the econometric estimates presented in the supplementary material.

Figure 12. Capital and operating expenditures for renewable energy under RPS.

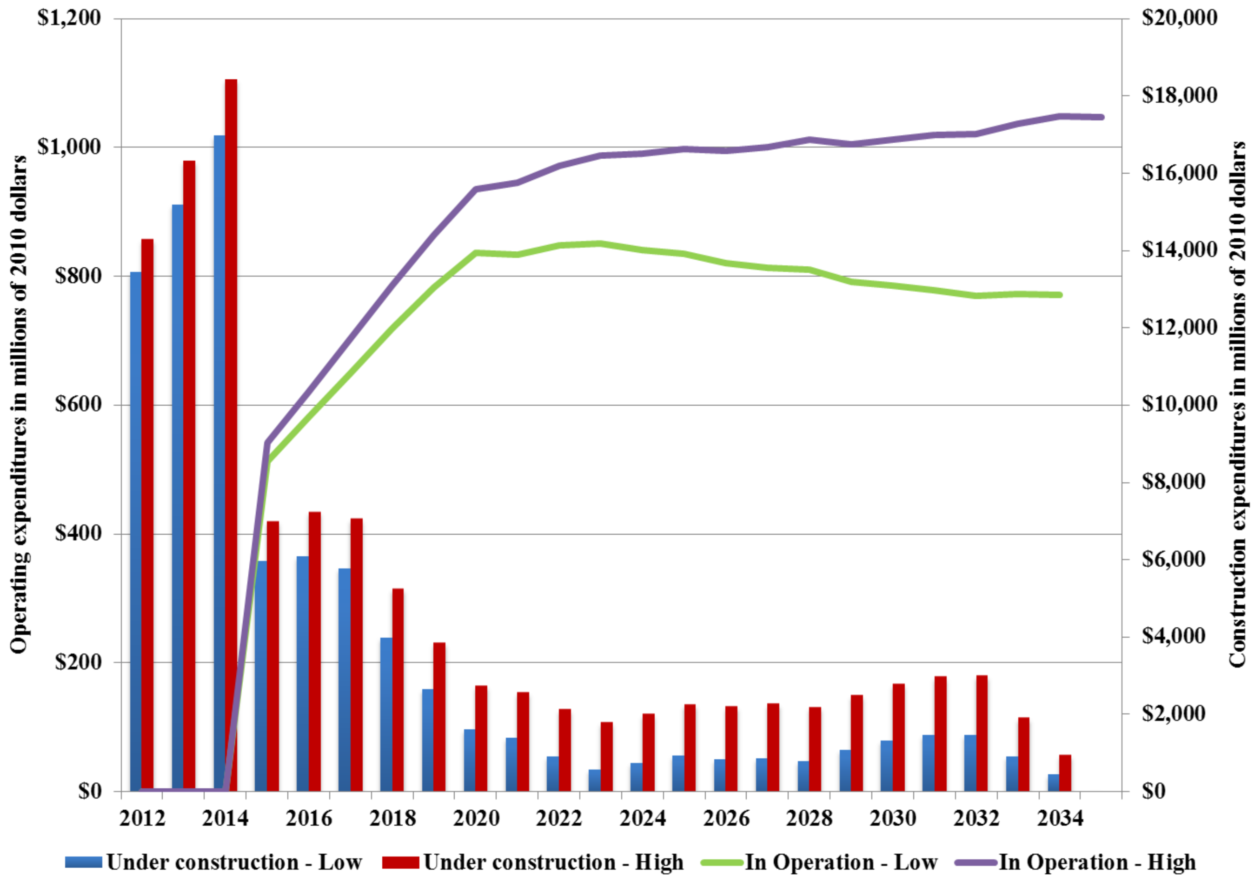
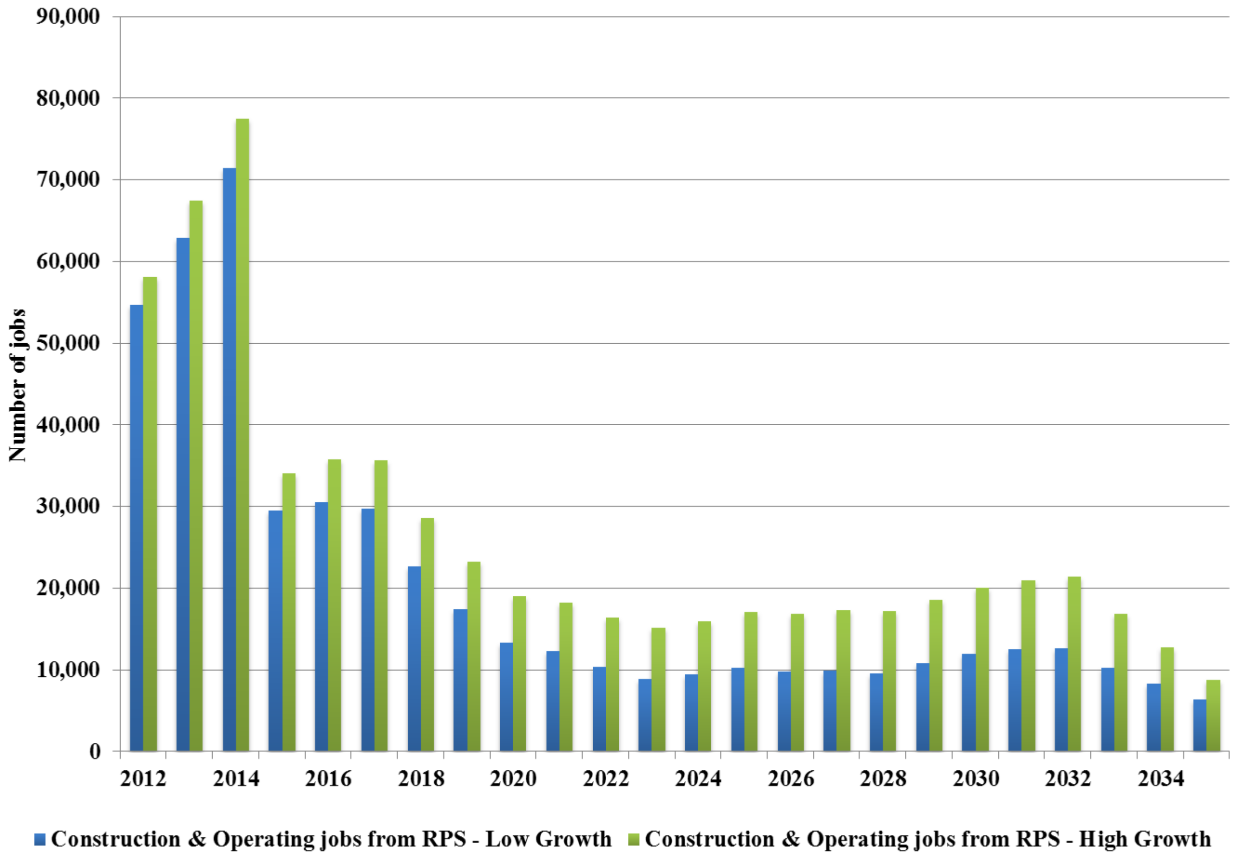


Figure 13. Gross employment gains under RPS scenario.



Given this very inelastic demand, when electricity prices increase in real terms, expenditures on electricity also increase. For instance, in 2015 consumers pay $2.4 billion dollars more for electric power than under the baseline scenario when economic growth is low. These additional expenditures rise to nearly $3.4 billion during 2020 and then fall slightly, averaging $2.7 billion per year thereafter. Electricity expenditures rise slightly more when economic growth is high as there is a greater build out of renewables.

During the early years of the RPS scenario, the stimulus from building the renewable energy facilities offsets the negative impacts of higher electricity expenditures. From 2012 to 2014, the average annual net gains in employment are 63,056 and 67,753 under the low and high growth scenarios respectively (see Table 3). After 2014, however, the net gains in employment and value added turn negative, and increasingly so, as the drag on economic growth from higher energy prices offsets any employment and output gains from building and operating the renewable energy facilities (see Table 3). The economic losses are slightly higher under the low growth scenario than under the high growth scenario. This is because in the high growth baseline the imported costs of electricity are higher, making the incremental costs of capacity addition and associated economic impacts smaller. The cost of imported electricity is higher in the high growth baseline because electricity imports continue to rise in the high growth baseline (see Subsection 4.1), and those imports beyond the peak levels of 2008 are more expensive (see Subsection 3.1).

Table 3. Net economic and environmental impacts from RPS scenario.

Year	Low growth scenario				High growth scenario			
	Jobs	Carbon Dioxide Emissions	Value Added	State tax revenues	Jobs	Carbon Dioxide Emissions	Value Added	State tax revenues
2012	54,744	0.00	4,955	545	58,147	0.00	5,263	579
2013	62,927	0.00	5,696	627	67,539	0.00	6,113	672
2014	71,496	0.00	6,471	712	77,574	0.00	7,021	772
2015	−11,362	−18.74	−1,032	−774	−7,684	−20.05	−698	−776
2016	−14,566	−21.08	−1,323	−905	−10,771	−22.80	−978	−920
2017	−19,676	−23.46	−1,788	−1,059	−15,880	−25.65	−1,443	−1,092
2018	−30,969	−25.89	−2,820	−1,279	−27,874	−28.61	−2,538	−1,339
2019	−39,886	−28.41	−3,664	−1,482	−37,680	−31.71	−3,462	−1,573
2020	−46,592	−30.58	−4,305	−1,645	−45,452	−34.52	−4,200	−1,772
2021	−46,310	−30.78	−4,286	−1,658	−45,488	−34.85	−4,210	−1,808
2022	−48,001	−31.70	−4,466	−1,718	−47,324	−35.92	−4,403	−1,890
2023	−48,598	−32.42	−4,551	−1,763	−48,153	−36.84	−4,510	−1,961
2024	−46,559	−32.68	−4,348	−1,746	−46,368	−37.38	−4,330	−1,969
2025	−44,453	−32.95	−4,139	−1,075	−44,342	−37.90	−4,129	−1,285
2026	−43,234	−33.48	−4,032	−981	−42,957	−38.69	−4,006	−1,201
2027	−41,478	−33.85	−3,853	−874	−40,890	−39.19	−3,798	−1,101
2028	−40,589	−34.63	−3,763	−784	−40,004	−40.21	−3,709	−1,021
2029	−37,657	−34.92	−3,469	−652	−37,030	−40.69	−3,411	−897
2030	−34,984	−35.60	−3,216	−552	−33,873	−41.58	−3,114	−799
2031	−32,456	−36.11	−2,981	−533	−30,429	−42.22	−2,795	−783
2032	−30,850	−37.04	−2,831	−510	−27,620	−43.29	−2,535	−761
2033	−31,513	−37.98	−2,902	−522	−29,513	−44.36	−2,718	−802
2034	−31,569	−38.97	−2,922	−554	−30,518	−45.50	−2,824	−859
2035	−31,167	−39.81	−2,911	−577	−30,492	−46.40	−2,848	−901

Notes: Carbon dioxide emissions are measured in million tons. Value added and state tax revenues are measured in millions of 2010 dollars.

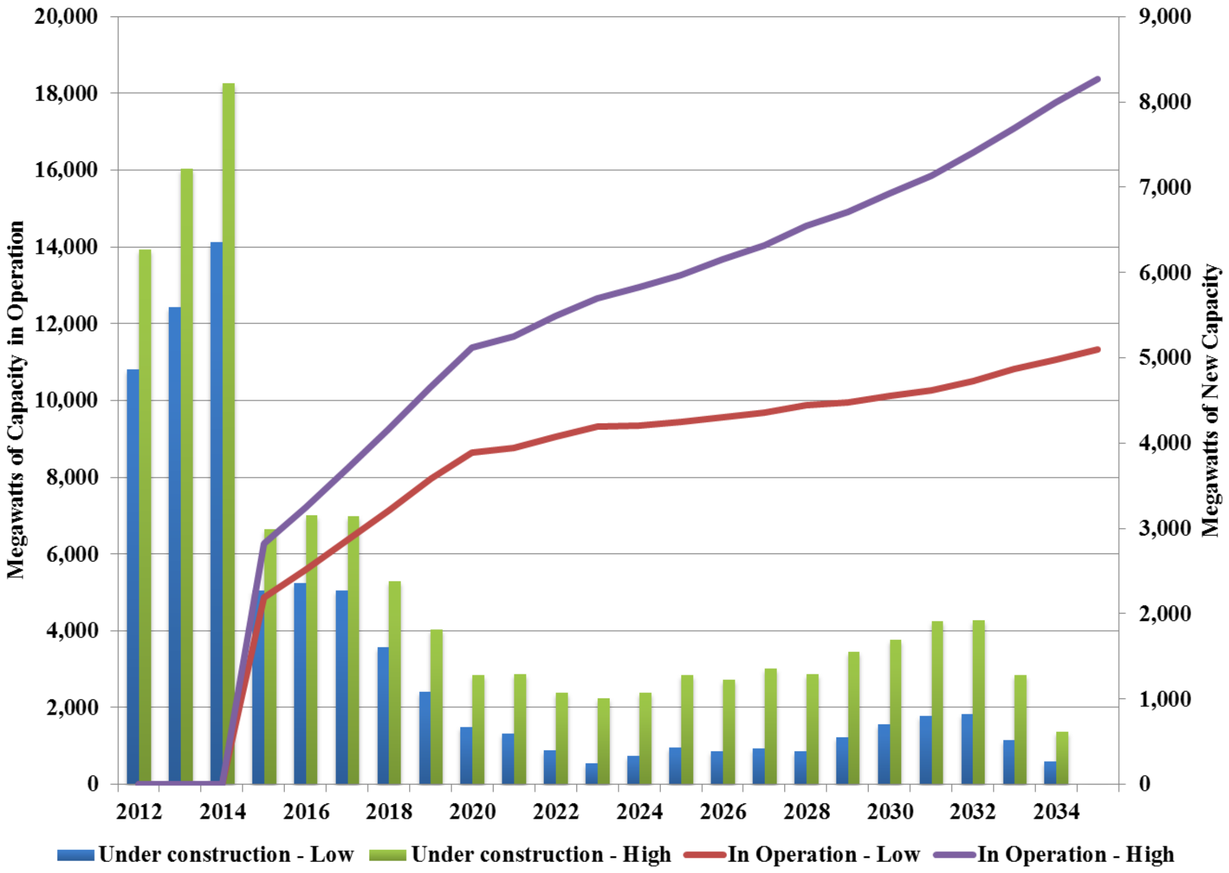
State tax revenues display a similar track. At first, state tax revenues increase by more than \$500 million in 2012 rising to over \$700 million in 2014. However, lower value added and employment under the RPS, in addition to the subsidy payments to renewable generation, subsequently lead to lower net tax revenues. By 2035, state tax revenues are \$577 million lower than under the baseline scenario with low growth and \$901 million lower than the high growth baseline forecast. From an economic and fiscal perspective, the RPS scenario examined in this study appears to generate short-term benefits but incurs significant long-term costs.

From an environmental perspective, however, the RPS scenario involves significant reductions in greenhouse gas emissions. Under the low growth scenario, carbon dioxide emissions steadily decline with early annual reductions of 19 million tons below baseline levels falling to 40 million tons by 2035. The reductions under the high growth scenario are larger, starting out 20 million tons lower than the baseline scenario to over 46 million tons by 2035. On the other hand, the reduction in carbon dioxide emissions is achieved at relatively high cost in terms of additional energy expenditures per ton of avoided emissions. Early in the forecast period, these carbon dioxide emission reductions cost between $121 and $128 per ton. While these costs decline to between $45 and $52 per ton by 2035, they remain well above market prices for carbon permit prices.

4.3. Impacts of Adopting Natural Gas Electricity Generation

Using natural gas-fired electric power generation to replace electricity imports and cut carbon emissions provides an alternative to the development of renewable electric power generation. Like the RPS scenario, the natural gas scenario requires the construction of new generation facilities. As Figure 14 illustrates, around 5,000 MW, or more, new natural gas based electric power generation capacity is under construction in each year from 2012 to 2014. The capacity additions then drop back in subsequent years, and after 2033 the construction phase draws to an end. Given this pattern of construction over time, the economic impacts follow a pattern similar to those of the renewable energy portfolio standard scenario.

Figure 14. New natural gas generation capacity.



Construction and operation economic impacts of natural gas are far lower than the RPS scenario. There are a number of reasons why. Firstly, each MW of natural gas capacity requires far less capital expenditures than each MW of the renewable technologies. Secondly, the relatively low capacity utilization rates of most renewable technologies require far greater MW of installed renewable capacity in order to generate the same level of electricity as natural gas capacity. Thirdly, a lower percentage of each dollar invested in natural gas is returned to California in benefits.

As Table 4 illustrates, during the first three years of the natural gas scenario, employment and valued added are higher than the baseline scenarios. For instance, in the low growth scenario, an average of more than 4,710 jobs are created during the plant construction phase from 2012 to 2014. Under the high growth scenario, the capacity requirements are greater and the employment gains are commensurately larger. Value added follows a similar track, expanding $370 to $484 million per year during the build out phase in the low growth scenario.

Table 4. Net economic and environmental impacts from natural gas scenario.

Year	Low growth scenario				High growth scenario			
	Jobs	Carbon Dioxide Emissions	Value Added	State tax revenues	Jobs	Carbon Dioxide Emissions	Value Added	State tax revenues
2012	4,093	0.00	370	41	5,272	0.00	477	52
2013	4,705	0.00	426	47	6,064	0.00	549	60
2014	5,345	0.00	484	53	6,907	0.00	625	69
2015	1,093	−2.20	99	11	1,218	−2.87	111	12
2016	1,093	−2.53	99	11	1,254	−3.29	114	13
2017	700	−2.87	64	7	839	−3.75	76	8
2018	−346	−3.22	−32	−3	−419	−4.23	−38	−4
2019	−1,206	−3.59	−111	−12	−1,449	−4.73	−133	−15
2020	−1,778	−3.89	−164	−18	−2,189	−5.18	−202	−22
2021	−2,366	−3.94	−219	−24	−2,731	−4.97	−253	−28
2022	−3,384	−4.09	−315	−35	−3,875	−4.87	−361	−40
2023	−4,033	−4.21	−378	−42	−4,468	−4.77	−418	−46
2024	−4,306	−4.23	−402	−44	−4,804	−4.63	−449	−49
2025	−4,544	−4.27	−423	−47	−4,936	−4.46	−460	−51
2026	−5,176	−4.34	−483	−53	−5,644	−4.32	−526	−58
2027	−5,680	−4.40	−528	−58	−5,927	−4.00	−551	−61
2028	−5,678	−4.48	−526	−58	−5,743	−3.75	−532	−59
2029	−5,281	−4.51	−486	−54	−4,967	−3.38	−457	−50
2030	−5,336	−4.58	−491	−54	−4,823	−3.06	−443	−49
2031	−5,995	−4.66	−551	−61	−5,192	−2.68	−477	−52
2032	−6,875	−4.79	−631	−69	−5,816	−2.31	−534	−59
2033	−7,681	−4.95	−707	−78	−6,419	−1.89	−591	−65
2034	−8,407	−5.08	−778	−86	−6,985	−1.45	−646	−71
2035	−9,417	−5.22	−880	−97	−7,650	−0.93	−715	−79

Note: Carbon dioxide emissions are measured in million tons. Value added and state tax revenues are measured in millions of 2010 dollars.

When the natural gas plants constructed come into operation, however, the higher electricity rates needed to pay the costs of constructing and operating these facilities cause a decline in economic activity. These new facilities are replacing relatively inexpensive imported electricity derived from coal, hydroelectric, and nuclear resources in the baseline scenarios. Like the renewable energy portfolio standard, as the cost of new natural gas plants enters the rate base, electricity rates increase and consumers and businesses pay for these higher rates by reducing spending, which has multiplied impacts on employment and output in the California economy.

Nonetheless, the net impacts initially remain positive. In 2015 there is a net creation of 1,093 jobs under the low growth scenario and 1,218 jobs under the high growth scenario. As construction declines further and natural gas prices continue to rise, however, the net impacts become negative. By the end of the forecast horizon, job losses rise to 9,417 under the low growth scenario and to 7,650 under the high growth scenario. Losses in value added follow a similar track, declining from a positive net impact in 2015 and by 2035 there is a loss in value added of $880 million under the low growth scenario and a loss of $715 million under the high growth scenario. While these impacts are not as severe as those under the RPS scenario, they underscore the importance of inexpensive sources of base load generation from coal, nuclear, and hydroelectric resources in maintaining low cost electricity for the California economy. Even though natural gas is now plentiful and relatively inexpensive, and thus the net effect of natural gas displacing the cheap mix of imports is initially positive, the projections of real cost increases for natural gas in future years used in this study increase the relative cost of electricity import replacement for California. These cost increases, however, may be mitigated if California could develop its own oil and natural gas resources.

4.4. Impacts of Developing Santa Barbara Oil

The final scenario involves developing crude oil and natural gas off the Santa Barbara coast. As this scenario is not a generation portfolio choice, it could be undertaken alongside the RPS or natural gas scenarios. Moreover, all the benefits in the Santa Barbara scenario are windfall gains, because retail electricity prices and expenditures do not rise. In addition, the expansion of oil and gas production simply displaces imported fuels and so in this respect is carbon neutral.

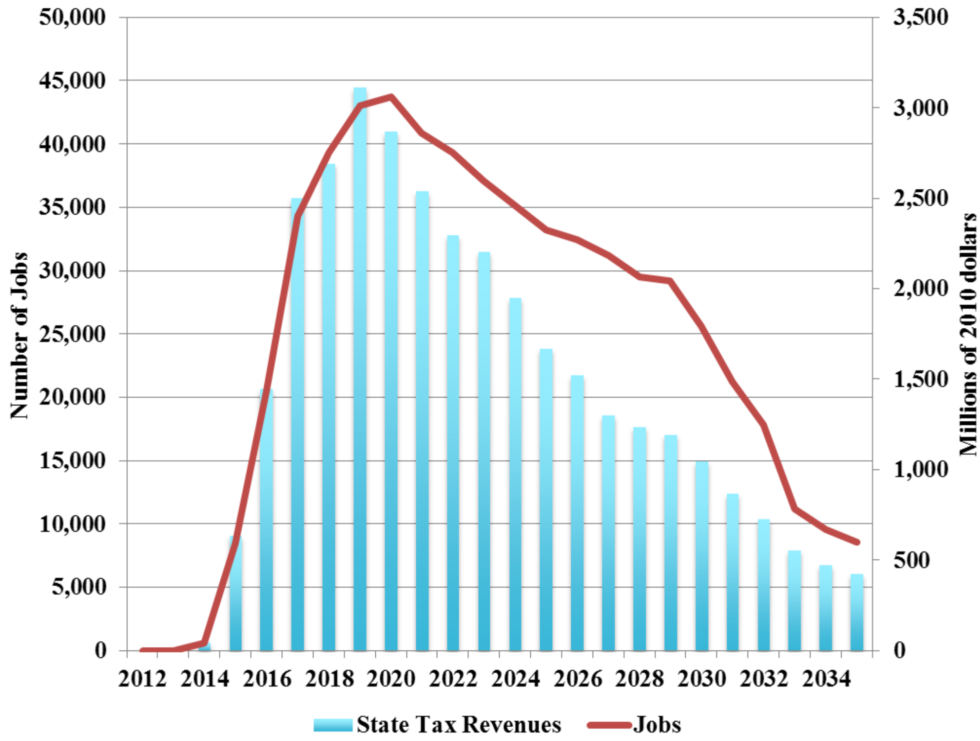
There are a number of counties or regions offshore California that could be the source of more oil and gas development. These counties include Orange, Los Angeles, Ventura, and Santa Barbara Counties. For the purpose of this paper, we are using the Santa Barbara Channel reserve as a case study. There could be significantly more production if reserves in other counties in the state were also developed.

Unlike the previous two scenarios, developing crude oil and natural gas reserves off the coast of Santa Barbara County would increase employment and state tax revenues over the next 25 years, as Figure 15 illustrates. At its peak, development creates over 43,000 jobs and generates more than $3 billion in tax revenue in 2020. This ability to increase employment and tax revenues at the same time stands in sharp contrast to the previous two scenarios.

This development opportunity also generates substantial tax revenue for the state of California. The vast majority of these revenues are property tax and royalty payments. In 2016, the total increase in revenue to the state purse is $1.4 billion, a figure that rises to $3.1 billion in 2019. By 2030, oil and gas development continues to provide over $1 billion in annual state and local taxes. The sizable windfall tax gains are similar to those generated by the Marcellus shale in Pennsylvania described by Considine [25]. Assuming the profile of these tax receipts to public agencies is similar to that observed in recent fiscal years in California, the state's contributions to the general fund, school districts and incorporated cities will all rise significantly under this offshore-development scenario.

Driving the gains in tax revenues and employment is higher valued added, which rises by $9 billion in 2020 and over $8 billion during most of the ensuing decade. Only when production declines after 2030 do the gains in value added decline. By 2035 the incremental gain in value added is $2.3 billion. Accordingly, if restrictions on offshore oil development were removed, additional Santa Barbara crude oil and natural gas production would by itself constitute a major new industry for the California economy. Furthermore, carbon emissions are actually marginally lower than under the baseline scenario because higher crude oil production in California reduces oil imports and the emissions associated with fewer oil tanker voyages.

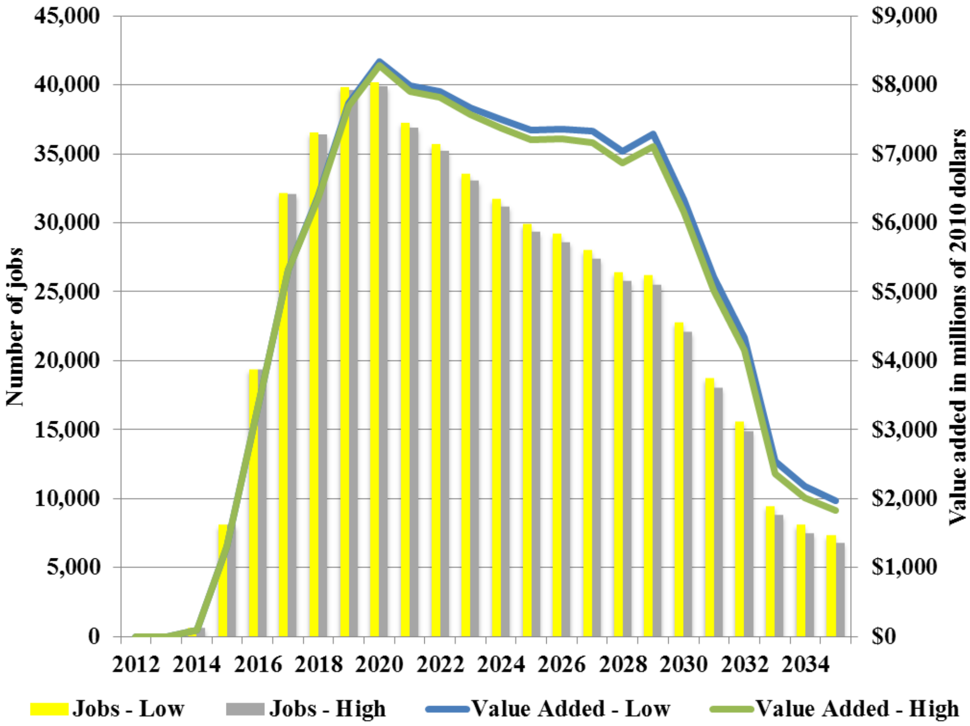
Figure 15. Jobs and tax revenues under the Santa Barbara oil scenario.



However, this analysis does not take into account the fact that higher value added, employment, and income would increase California's energy demand and energy expenditures. In turn, this would offset some of the gains from development. To assess the importance of the feedback effect from higher energy expenditures, the energy model is solved with higher gross state product values from the first round impacts of development and the economic impact analysis is recomputed. The results of this analysis appear in Figure 16. As expected, the employment and value added gains are slightly smaller under the low and high growth scenarios with feedback than without. In addition, the feedback effect is stronger under the high growth scenario than the low growth scenario because the economic multipliers are affecting a larger base of economic activity. Thus, with feedback, the net gains of Santa Barbara development are slightly lower with high, as opposed to low, growth.

Carbon emissions are slightly higher with feedback than in the baseline scenarios, because the emissions savings from reduced tanker traffic are offset by higher energy consumption and emissions resulting from the economic gains of Santa Barbara development. However, the increase in carbon emissions is never more than 0.9 million tons in a given year. So even allowing for the feedback of higher economic growth on energy demand and carbon dioxide emissions, the environmental impacts from an air emissions standpoint are minor. Any damages to land and water are also likely to be minimized since development of these offshore resources would take place on land using innovative directional drilling technologies.

Figure 16. Economic Impacts under the Santa Barbara oil scenario with feedback.



These findings also suggest that development of crude oil and natural gas resources onshore in the prospective Monterey Shale could provide similar benefits, potentially at a much larger scale, enhancing economic growth, job creation, and fiscal balance, and providing the resources for education, social services, and environmental protection. Indeed, developing crude oil and natural gas resources in California may be a good strategy to offset the economic losses resulting from the implementation of the California Renewable Energy Resources Act.

5. Summary and Conclusions

The aim of this paper is to shed some light on the trade-offs involved in supplying California's energy future. In particular, we consider various technological paths for supplying California's energy, and in each case look at how much energy will be required, the costs to society of supplying this energy, the implications for carbon emissions, and the economic impacts. If California were to continue as it has done in the recent past, excess electricity demand requirements will be met with imports. This is our baseline scenario. Although it would make California even more reliant upon other states, it would also save on the capital installation costs required to increase its own generation capacity base. What would this scenario mean for the typical California household? During 2010, the average household spent around $265 per month on electricity, gasoline and other fuels. These expenditures rise to $437 per month in today's dollars by 2035 with low growth, and to $474 per month with high growth, under our baseline forecast.

This study estimates the economic, energy, and environmental impacts of three scenarios for California's energy future. The first scenario involves full implementation of the California Renewable Energy Resources Act, which would require 33% of electricity to be supplied by renewable energy by 2020. This study assumes that this scenario would also involve achieving a 40% renewable energy share by 2035. To achieve these goals, California utilities and power companies would need to invest heavily in new solar, wind, and other renewable energy capacity. These policies by default would make California more energy self-sufficient, moving away from its current reliance on imports of electricity. The second scenario is based upon the same import displacement strategy by expanding natural gas capacity to generate electricity within California.

The third and final scenario involves developing crude oil and natural gas deposits. For illustrative purposes we chose as an example the oil and gas deposits off the coast of Santa Barbara, California. Like the previous two scenarios, capital investments are required to build facilities to extract these resources. Given that oil prices are determined on international markets, this scenario does not affect prices for petroleum products paid by California consumers. Two separate scenarios are developed for this case, with and without a feedback between economic growth and energy demand.

A summary of the key findings appears below in Table 5. The first finding is that the economic impacts of developing Santa Barbara are positive with the creation of between 22,000 and almost 25,000 jobs annually, between $82 and $92 billion in value added, and over $23 billion in state tax revenues over the next 25 years. These gains are achieved with minimal environmental impact. Carbon emissions are actually lower due to savings arising from reduced imported oil tanker traffic. If higher economic growth is taken into account, carbon emissions rise compared to the baseline scenarios but the increase is very minor.

In contrast, the RPS and natural gas scenarios significantly reduce greenhouse gas emissions but involve reductions in employment, value added, and tax revenues in the long run. During the early years of these two scenarios, employment and value added increase over the baseline scenario. As the costs of constructing these facilities are recovered, however, electricity rates increase. These higher rates reduce consumer discretionary income and cash flow for businesses. The overall impact of the higher energy expenditures is to offset the economic stimulus from building renewable or natural gas power generation plants.

Our energy model assumes that all new electricity imports beyond the peak levels of 2008 are from gas-fired generation, while the portfolio of California's existing imports of electricity is constant over the forecast horizon (*i.e.*, 47% coal, 20% natural gas, 23% hydroelectric, and 10% nuclear resources). Allowing for some of the existing import generation base to be replaced with an alternative generation technology could reduce the magnitude of the estimated negative impacts of the RPS and natural gas scenarios. This is because in the baseline scenario there is a greater reliance on the cheap existing import mix. The main area of dispute would be whether the share of coal in California's existing imports would fall in the future. However, the latest electricity generation forecasts published by the EIA for the western region excluding California indicate that total coal-fired electricity generation will actually remain fairly constant at around 200 billion kilowatt-hours out to 2035. The biggest change is the increase in renewable generation from 156 billion kilowatt-hours in 2010 to 255 billion kilowatt-hours by 2035. However, this adjustment may reflect efforts by the states surrounding California to serve their own retail customers using renewable energy in response to their own RPS policies. Hence this trend may not affect California's existing portfolio of imports.

By modeling direct, indirect and induced economic impacts, we fully capture industry-to-industry interactions. We also capture the impact that an electricity generation strategy may have on electricity prices and expenditures, which can in turn affect economic outcomes. These are issues that are often ignored by existing green job studies (see Wei *et al.* [17] for a discussion). On the other-hand, we do not take into account job losses in the operation of electricity generation facilities that may occur outside of California following an electricity import displacement strategy. This could mean the wider economic impacts of the RPS or natural gas scenario are slightly more negative than reported here (although most job impacts arise from construction and not operation).

We capture the changing profile of construction and operation costs of the electricity generation technologies over time using EIA forecasts. This includes learning curve information. Consequently, jobs-years per MW installed or jobs per MW in operation also vary over the forecast horizon. On the other-hand, as the EIA cost data are national averages, we do not capture regional or project-specific variation, although we do customize capacity utilization rates for solar thermal, PV and wind to reflect the likely performance of these technologies in California. In addition, a limitation to our analysis is that we assume that economic data used to compile the input-output models, in particular economic multipliers, are constant over the forecast horizon. This caveat is difficult to overcome, although it should not substantially affect the estimated construction impacts from building renewable or natural gas generation facilities, which mostly take place over the first five or so years of the forecast horizon. Nonetheless, we emphasize that these results are intended to be estimates and not precise predictions.

Table 5. Summary of economic and environmental impacts.

Net Impacts on	**Scenarios**			
	Renewable Energy Portfolio	**Natural Gas**	**Santa Barbara Oil**	**Santa Barbara Oil with Feedback**
Employment	*Average Annual Number of Jobs*			
Low Growth	−23,471	−2,936	24,659	22,471
High Growth	−21,545	−2,603		22,143
Value Added	*Present Value in Millions of 2010 Dollars*			
Low Growth	−29,982	−3,380	91,769	83,609
High Growth	−26,668	−2,893		82,397
State Tax Revenues				
Low Growth	−13,420	−372	23,786	23,371
High Growth	−15,656	−318		23,310
Carbon Dioxide Emissions	*Cumulative in millions of tons*			
Low Growth	−671	−86	−3	12
High Growth	−768	−76		14

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