

# Electricity Market Module

The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and load and demand (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from CHP and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990 (CAAA90) and the Clean Air Interstate Rule. The *AEO2009* also models State-level regulations implementing mercury standards. The EMM also has the ability to track and limit emissions of carbon dioxide, and the *AEO2009* includes the regional carbon restrictions of the Regional Greenhouse Gas Initiative (RGGI).

Operating (dispatch) decisions are provided by the cost-minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region and season. The solution to the submodules of EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be viewed as follows:

- The electricity load and demand submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of equipment for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched to meet another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal-cost based electricity prices.

## Electricity Capacity Planning Submodule

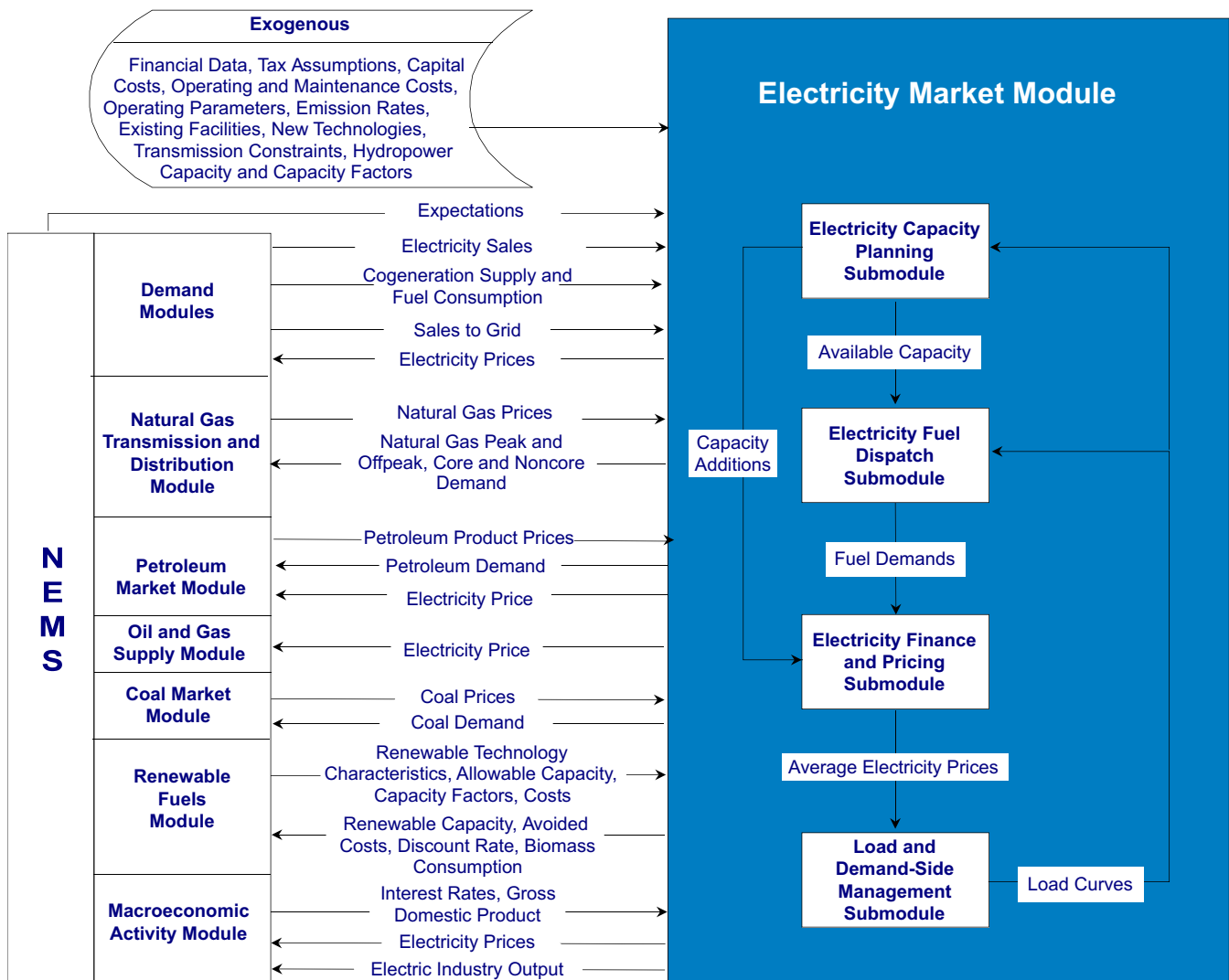
The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology chosen is determined by the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies, and the construction and operating costs of available technologies.

The expected utilization of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (primarily fuel costs) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components Fuel demands Capacity additions Capital requirements Emissions Renewable capacity Avoided costs	Electricity sales Fuel prices Cogeneration supply and fuel consumption Electricity sales to the grid Renewable technology characteristics, allowable capacity, and costs Renewable capacity factors Gross domestic product Interest rates	Financial data Tax assumptions Capital costs Operation and maintenance costs Operating parameters Emissions rates New technologies Existing facilities Transmission constraints

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Figure 9. Electricity Market Module Structure



by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants.

Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable central-station generating technologies are represented, as listed in Table 11. The EMM also considers two distributed generation technologies -baseload and peak. The EMM also has the ability to model a demand storage technology to represent load shifting.

Uncertainty about investment costs for new technologies is captured in ECP using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

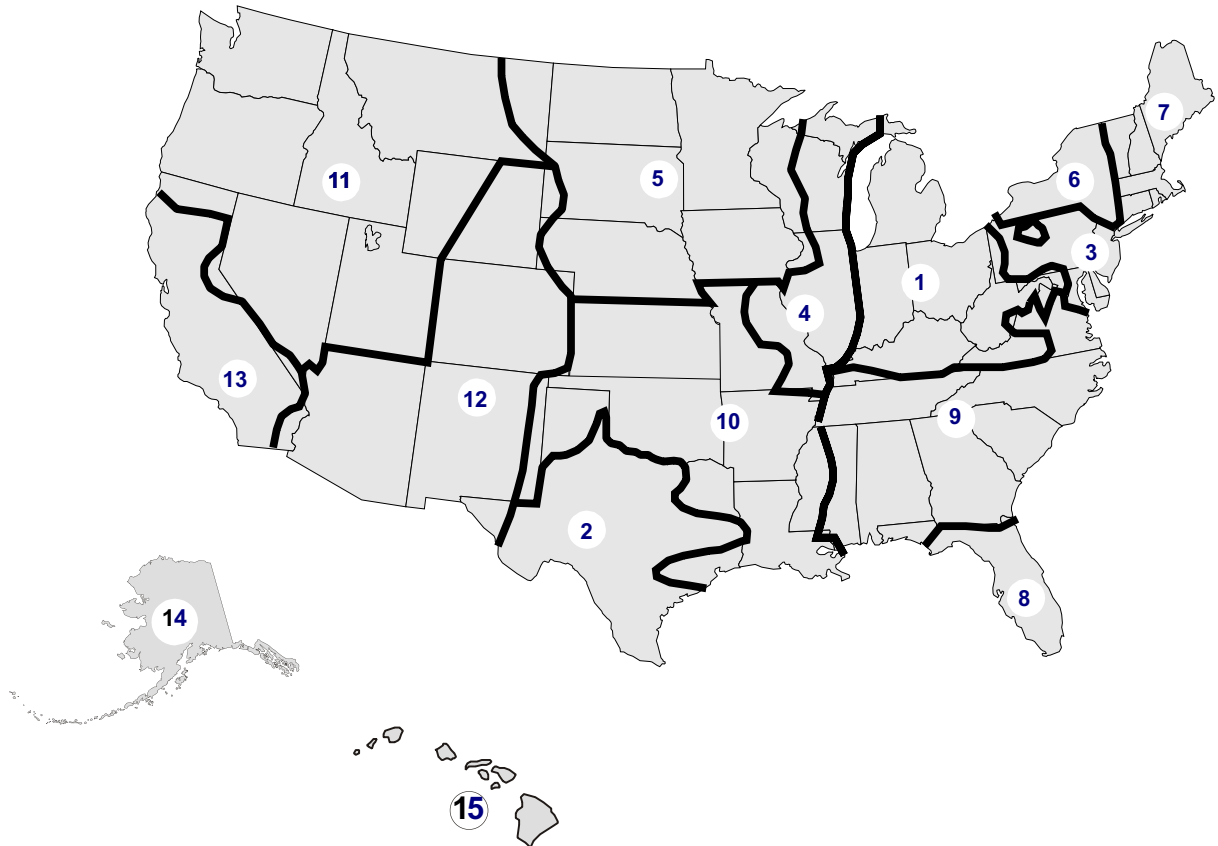
Learning factors represent reductions in capital costs due to learning-by-doing. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. These factors

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Figure 10. Electricity Market Module Supply Regions

Electricity  
Supply  
Regions

- 1 ECAR
- 2 ERCOT
- 3 MAAC
- 4 MAIN
- 5 MAPP
- 6 NY
- 7 NE
- 8 FL
- 9 STV
- 10 SPP
- 11 NWP
- 12 RA
- 13 CNV
- 14 AK
- 15 HI



are calculated for each of the major design components of a plant type design. For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. A 3-step learning curve is utilized for all design components.

Typically, the greatest amount of learning occurs during the initial stages of development and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availability from the *AEO2009* reference case are shown in Table 12; capital costs represent the costs of building

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new plants ordered in 2008. Additional information about costs and performance characteristics can be found on page 89 of the "Assumptions to the Annual Energy Outlook 2009."<sup>17</sup>

Initially, investment decisions are determined in ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil-fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going-forward costs, which are mainly fuel and O&M costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule.

## Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable

Table 11. Generating Technologies

<b>Fossil</b>
Existing coal steam plants (with or without environmental controls) New pulverized coal with environmental controls Advanced clean coal technology Advanced clean coal technology with sequestration Oil/Gas steam Conventional combined cycle Advanced combined cycle Advanced combined cycle with sequestration Conventional combustion turbine Fuel cells
<b>Nuclear</b>
Conventional nuclear Advanced nuclear
<b>Renewables</b>
Conventional hydropower Pumped storage Geothermal Solar-thermal Solar-photovoltaic Wind - onshore and offshore Wood Municipal solid waste
<small>Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipment.</small>

costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal-fired capacity can co-fire with biomass in order to lower operating costs and/or emissions.

The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. It simulates the electric transmission network on the NERC region level and simultaneously dispatches capacity regionally by time slice until demand for the year is met. Traditional cogeneration and firm trade capacity is removed from the load duration curve prior to the dispatch decision. Capacity costs for each time slice are based on fuel and variable O&M costs, making adjustments for RPS

17 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, [http://www.eia.doe.gov/oiia/aeo/assumption/pdf/0554\(2009\).pdf](http://www.eia.doe.gov/oiia/aeo/assumption/pdf/0554(2009).pdf) (March 2009)

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credits, if applicable, and production tax credits. Generators are required to meet planned maintenance requirements, as defined by plant type.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace energy in an importing region if it results in a cost savings. After dispatching, fuel use is reported back to the fuel supply modules and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

## Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the electricity finance and pricing (EFP) submodule, which simulates both competitive electricity pricing and the cost-of-service method often used by State regulators to determine the price of electricity. The AEO2009 reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the

Table 12. 2008 Overnight Capital Costs (including Contingencies), 2008 Heat Rates, and Online Year by Technology for the AEO2009 Reference Case

Technology	Capital Costs <sup>1</sup> (2007\$/KW)	Heatrate in 2008 (Btu/kWhr)	Online Year <sup>2</sup>
Scrubbed Coal New	2058	9200	2012
Integrated Coal-gasification Comb Cycle (IGCC)	2378	8765	2012
IGCC with carbon sequestration	3496	10781	2016
Conventional Gas/Oil Comb Cycle	962	7196	2011
Advanced Gas/Oil Comb Cycle (CC)	948	6752	2011
Advanced CC with carbon sequestration	1890	8613	2016
Conventional Combustion Turbine	670	10810	2010
Advanced Combustion Turbine	634	9289	2010
Fuel Cells	5360	7930	2011
Adv nuclear	3318	10434	2016
Distributed Generation - Base	1370	9050	2011
Distributed Generation - Peak	1645	10069	2010
Biomass	3766	9646	2012
MSW - Landfill Gas	2543	13648	2010
Geothermal <sup>3</sup>	1711	34633	2010
Conventional Hydropower <sup>3,4</sup>	2242	9919	2012
Wind <sup>4</sup>	1923	9919	2009
Wind Offshore <sup>4</sup>	3851	9919	2012
Solar Thermal	5021	9919	2012
Photovoltaic	6038	9919	2011

<sup>1</sup>Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2008. Capital costs are shown before investment tax credits are applied, where applicable.

<sup>2</sup>Online year represents the first year that a new unit could be completed, given an order date of 2008. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occurring in anticipation of the expiration of the Production Tax Credit in 2009 for wind and 2010 for the others.

<sup>3</sup>Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

<sup>4</sup>For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2007. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

Using historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission Form 1, Annual Report of Major Electric Utilities, Licensees and Others, and Form EIA-412, Annual Report of Public Electric Utilities), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, the EFP also determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand. The competitive price also includes a reliability price adjustment, which represents the value consumers place on reliability of service when demands are high and available capacity is limited. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

## Electricity Load and Demand Submodule

The electricity load and demand (ELD) submodule generates load curves representing the demand for electricity. The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD submodule generates load curves for each region and season.

## Emissions

EMM tracks emission levels for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). Facility development, retrofitting, and dispatch are constrained to comply with the pollution constraints of the CAAA90 and other pollution constraints including the Clean Air Interstate Rule. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance.

In addition to SO<sub>2</sub>, and NO<sub>x</sub>, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO<sub>2</sub> and mercury emissions. Selective catalytic reduction can reduce NO<sub>x</sub> and mercury emissions. Selective non-catalytic reduction and low-NO<sub>x</sub> burners can lower NO<sub>x</sub> emissions. Fabric filters and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.

The *AEO2009* includes a generalized structure to model current state-level regulations calling for the best available control technology to control mercury. The *AEO2009* also includes the carbon caps for States that are part of the RGGI.