OLR RESEARCH REPORT

January 30, 2012 2012-R-0073

DRAFT ELECTRIC INTEGRATED RESOURCES PLAN

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You asked for a summary of the draft 2012 integrated resources plan (IRP) prepared by the Department of Energy and Environmental Protection (DEEP). Background on the plan's development is available at http://www.ct.gov/deep/cwp/view.asp?a=4120&q=486946.

SUMMARY

PA 11-80 requires DEEP to prepare the IRP; under prior law the electric companies prepared the plan. The plan is "integrated" in that it looks at both demand side resources, e.g., energy efficiency programs, as well as the more traditional supply side resources , e.g., power plants, in making its recommendations on how best to meet future electric energy needs in the state.

The draft plan's principal findings include the following.

1. Over the next several years, consumption in the state is expected to grow slowly, not surpassing 2005 levels until 2022.

2. Based on reasonable assumptions about market conditions and the completion of transmission projects, adequate generating

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resources will be available in Connecticut to serve electricity loads reliably through 2022 under every scenario the IRP analyzes.

3. The generation service charge (which reflects the wholesale price of power bought by the electric companies) should remain at or below 8¢ per kilowatt-hour (kWh) through 2017, as expanding gas supplies moderate wholesale natural gas and power prices. However, from 2017 to 2022, the charge is projected to rise by more than 3¢ per kWh in real terms.

4. Connecticut's renewable portfolio standard (RPS) requires electric companies and competitive suppliers to get part of their power from renewable resources. But, unless more renewables are developed across New England than are currently projected, a gap between available supply and mandated demands will emerge in 2018. The companies and suppliers would have to offset the shortage by making alternative compliance payments that could cost up to $250 million per year by 2022. The payments are used to develop renewable projects in the state.

5. Emissions of air pollutants, including carbon dioxide (CO_2) have fallen from their 2007 levels, and are projected to continue falling through 2015. Thereafter, emissions will rise very slowly as electricity demand grows, but remain below 2010 levels through 2022.

The plan recommends that, in light of expected rate increases from 2017 to 2022, the state pursue strategies that:

1. help customers reduce their consumption and save money;

2. facilitate the development of low-cost, clean resources that are economically feasible but may face barriers to implementation;

3. find more effective ways to meet the clean energy objectives of the RPS without exposing customers to potentially excessive costs; and

4. support in-state jobs.

Specifically, the plan recommends that the state increase conservation and load management budgets from $105 million annually under a business-as-usual budget to $206 million annually. The plan estimates that doing this would result in a net savings of $534 million per year by 2022 compared to a business-as-usual base case.

The plan also recommends that electric companies and competitive suppliers be given more flexibility in meeting the RPS to avoid having their customers paying large amounts of alternative compliance payments. The plan recommends that (1) the savings attributable to new energy efficiency programs be allowed to count towards part of the RPS requirements and (2) policymakers consider allowing other resources, such as out-of-region large hydropower, to count towards the RPS requirements.

The IRP also investigates the potential costs and benefits of building a new power plant on a cost-of-service basis that would go into service in 2017. It finds that this would be uneconomic, although building a plant that opens in 2020 might be.

The plan does not address the electric industry's response to storms and the resiliency of the distribution system, since they are the subject of an ongoing investigation by the governor's office. Similarly, the plan does not cover the procurement of wholesale power to serve customers who choose to buy generation from the electric companies because it will be addressed by DEEP's new procurement manager, a position created by PA 11-80.

PA 11-80 requires DEEP to hold a hearing on the plan, which is not a contested case. It must post the plan on its website (www.ct.gov/deep) and provide at least 45 days for public review and comment. The DEEP commissioner must consider fully, after all public meetings, all written and oral comments concerning the proposed plan. The commissioner must approve or reject the plan with comments. The commissioner must make available the electronic text of the final plan or a web site where it is posted, and a report summarizing (1) all public comments and (2) the changes made to the final plan in response to such comments and the reasons for doing so.

INTRODUCTION

PA 11-80 requires DEEP, rather than the electric companies, to (1) assess future electric demands and how best to meet them and (2) develop an IRP to meet the demands through procuring a mix of generating facilities and efficiency programs. DEEP must consult with

Connecticut Energy Advisory Board and the electric companies in conducting the assessment. By law, (1) the plan must cover the next three, five, and tens years and (2) the resource needs identified in the plan must first be met through all available and cost-effective efficiency and demand reduction measures.

Base Case

DEEP began the planning process by developing a base case, based on its outlook for Connecticut's and New England's resource needs. The base case addresses system reliability, customer rates, and emissions. It assumes that proposed new transmission lines in Connecticut will be built, helping the state to meet its demand using local resources. OLR Report 2012-R-0028 describes a key component of the proposed project that would construct a new transmission line in northeastern Connecticut.

The base case forecasts slow demand growth due to the current economic conditions, continued utility energy efficiency programs, and new energy efficiency codes and standards. The IRP projects that, under the base case, the surplus in generation capacity will be large enough to withstand the effect of (1) likely generation facility closings resulting from the implementation of the federal Environmental Protection Agency's proposed air toxics rule in three to four years and (2) the end of the floor on prices paid to generators for their generating capacity. (Generators are paid for making their plants available to provide additional power if demand is higher than expected. Currently, there is an administratively set floor on these payments that will end in 2016). The base case assumes that a number of power plants in New England, including the Vermont Yankee nuclear power plant, will close.

Alternative Scenarios

The IRP then analyzes how outcomes could change under alternative market conditions, including differing levels of natural gas prices, overall economic growth, and generation supply. The "tight supply" future incorporates a high economic growth load forecast developed by ISO New England, the entity that administers the regional wholesale electric market. Under this forecast, demand in 2020 would be 1,150 megawatts (MW) higher than the amount used in the base case. This is about the amount of generating capacity of two conventional power plants. The "tight supply" future also (1) does not allow active demand response measures (where a customer chooses to reduce short-term demand in response to market signals) to adjust to capacity price changes and (2) assumes Boston's resource shortages are solved by transmission lines

instead of adding generation resources there. The "Abundant Supply" future (1) incorporates ISO New England's low economic growth load forecast (1,150 MW less demand by 2020) and (2) assumes the Vermont Yankee plant remains in service during the study period. The "high gas" future projects the impact of gas prices that are 60% higher than those in the base case, while the "low gas" future projects prices that are 40% below the base.

Evaluating Policy Options

Next, the IRP evaluates several policy options that could reduce costs and emissions while supporting in-state jobs. These involve pursuing additional energy efficiency, renewable generation (including resources located outside of New England), and new conventional generation. The plan tests the robustness of these scenarios against the base case and alternative futures.

While the base case assumes that energy efficiency program funding will continue at current levels, the expanded energy efficiency option nearly triples that amount over the next decade. The opportunities for increased efficiency and the costs of achieving them are based on a 2010 study commissioned by the Energy Conservation Management Board.

The IRP analyzes two ways of meeting the state's RPS, specifically with regard to class I resources such as solar and wind energy. (There are also class II and class III resources, e.g., the power produced by waste-to-energy plants and the energy saved by new efficiency programs, respectively). The first option maintains the current RPS requirements, and examines three levels of Class I development: a low case, a base case, and a full renewables build-out. As an alternative, the IRP considers a statutory change that would allow Class III renewable energy credits created by efficiency programs to meet part of the Class I requirements.

Finally, the IRP looks at what would happen if a new, efficient 656 MW gas-fired combined-cycle plant was built in Connecticut in 2017 on a cost-of-service basis, backed by power purchase agreements or other support from Connecticut customers. (Under cost of service, the payments made to the plant's owners are based on its costs, rather than on the wholesale market as is the case now.) The concept of this policy option is to examine the value to Connecticut customers of paying the full cost of new conventional generation and receiving its full market value, doing so before such a resource would have been developed by merchant developers.

ELECTRIC DEMAND AND SUPPLY

Demand

Peak load in Connecticut declined during the recession, but ISO New England forecasts an annual growth rate of 1.7% or 125 megawatts (MW) per year in the state over the next few years, with the annual growth decreasing to 0.9% (75 MW/year) by 2020. ISO-New England forecasts that the New England system peak load will grow at an annual rate of 2.0% initially (545 MW/year), decreasing to 1.1% growth (340 MW/year) by 2020. These peak load projections do not deduct the effects of energy efficiency, most of which is counted separately as a supply-side resource. In the base case, consumption in the state will not surpass 2005 levels until 2022.

Supply

As of January 1, 2011, there are 8,150 MW available in Connecticut and 32,027 MW available regionally to meet reliability requirements. (For reasons discussed below, the Connecticut number does not include the generating capacity of the Lake Road power plant in northeastern Connecticut.) The plan anticipates that the 130 MW New Haven Harbor gas turbine plant will begin operating in June 2012 and the 88 MW expansion of the Northfield Mountain pumped-storage plant in Massachusetts will be completed by summer 2015.

The IRP does not anticipate that any other non-renewable generation will be built until 2022 or 2023 in the base case. It assumes that new generation will only be built when the price paid to generators for their capacity rises to the net cost of building a gas-fired combined-cycle plant. It anticipates that demand reductions by customers in response to changing market prices will help meet overall demand until 2022. In the tight supply future, new generation would be needed in 2018. In the high gas supply future (where gas prices are low), new generation would be needed in 2019. This is because lower gas prices reduce electricity prices, increasing demand.

Demand for renewable energy is largely driven by the RPS in Connecticut and other states. Planned additions of renewable generation are 46 MW in Connecticut and 170 MW region-wide. Much of the renewable generation projects being developed elsewhere in New England are wind projects that only generate power part of the time. Therefore, this generation results in only 69 MW of available capacity. The renewable generation includes projects being developed for Project 150 in Connecticut as well as additional onshore wind and solar photovoltaic

that are currently being developed or have announced plans to build. In addition, the IRP assumes that an additional 343 MW (150 MW available capacity value) of renewables that are not yet planned will be developed in Connecticut and 2,470 MW (766 MW available capacity) region-wide to help meet RPS requirements in Connecticut and other states.

The IRP takes into account the planned closing of the 183 MW AES Thames plant in Connecticut and assumes the loss of an additional 1,366 MW elsewhere in New England, including Vermont Yankee. The IRP has scenarios where additional plant closings take place, depending on fuel prices and other factors.

Resource Adequacy

ISO-New England has established several standards of resource adequacy to ensure reliable electric supply. Under all likely scenarios, Connecticut will have enough resources to meet all of these standards, assuming that the proposed New England East-West System transmission project is completed. The IRP states that this project will help Connecticut to meet its demand from local resources. In part, this is because the project will incorporate the existing 745 MW Lake Road power plant in the Connecticut grid. Although the plant is located in Connecticut, it currently cannot ship power to the rest of the state and is considered part of the Rhode Island grid. When the project is completed between 2013 and 2016, it will also increase Connecticut's ability to import power from other states by 1,100 MW. With this project, locally-available resources, including imports, would be adequate to meet Connecticut's needs even if all 2,716 MW of the fossil fuel generating capacity in Connecticut closed when the capacity price floor is eliminated in 2016.

On the other hand, Connecticut could face a supply shortfall under certain circumstances. According to the IRP, in a worst case scenario Connecticut could face a shortfall of up to 550 MW if: (1) all fossil generating units in the state close; (2) the Central Connecticut portion of the New England East-West Solution (the only part of the transmission project ISO-NE has not yet approved) is not constructed, reducing the import limit by 200 MW; (3) ISO New England's "high economic growth" forecast is realized, with peak demand in Connecticut about 350 MW higher than the base case forecast by 2022; and (4) all the older combustion turbines retire due to potential future nitrogen oxides (NOx) regulations. The IRP considers this combination of events to be very unlikely, but recommends that DEEP monitor the situation and ensure measures would be in place to mitigate any shortfalls.

Price

A key component of electric prices is the price of natural gas, which usually sets the price in the regional wholesale electric market. In recent years, natural gas prices have fallen significantly, in part due to production from the Marcellus Shale and similar geological formations in the United States.

The IRP anticipates that the wholesale price of natural gas will be stable for several years. As a result, it projects that the annual average wholesale energy prices in 2015 will be $54.6 per megawatt-hour (MWh) in 2015, compared to $87/MWh in 2008 (when natural gas prices were much higher) and $52 in 2010 (all in 2012 dollars). The IRP projects that the energy price will increase to $56.3/MWh in 2017, and $61.5/MWh in 2022, again in constant 2012 dollars. About two thirds of the expected increase is due to rising natural gas prices and the remaining third is due to less efficient generators setting market prices more often as demand grows and the capacity surplus shrinks.

At the retail level, the IRP projects that the generation services component of rates, which reflects the electric companies' wholesale cost of power, will remain below 8¢ per kWh through 2017. However, from 2017 to 2022, the generation service charge is likely to increase by slightly more than 3¢/kWh.

This projected increase is driven by three factors:

1. about 1.9 ¢/kWh of the increase is from rising capacity prices;

2. about 0.6¢/kWh of the increase is associated with the RPS, due to (a) the increasing share of power that the law will require electric companies and competitive suppliers to get from renewable resources, (b) the higher prices of these resources and (c) the transmission improvements needed to support increased Class I resources; and

3. about 0.6¢/kWh of the increase is from rising wholesale energy prices, approximately two-thirds of which is caused by higher natural gas prices, and one-third by the increasing use of relatively inefficient plants as demand grows.

Prices would be higher in the high gas cost and tight supply futures and lower in the low gas cost and abundant supply futures.

ENERGY EFFICIENCY

The expanded energy efficiency resource option is based on a 2011 study sponsored by the Energy Conservation Management Board. The study (1) estimates the savings that could be achieved based on a detailed analysis of hundreds of individual measures in each customer sector and (2) applies a benefit-cost test to each measure to estimate its economic potential. Most of the measures extend ones already being implemented by the electric companies; many would involve significantly expanding the more innovative parts of existing programs, such as offering technical training to commercial customers on more efficient practices.

Expanding the current efficiency programs would reduce peak demand by 1,071 MW by 2022 compared to the base case. The IRP assumes an 11-year implementation schedule. Because each measure saves energy over the entire life the equipment is installed, the savings from each year's measures accumulate on top of prior years' accomplishments as capital equipment becomes increasingly efficient. If this option were implemented, energy consumption in Connecticut would continually decline by about 0.4% per year and result in 4,339 GWh savings in 2022.

The annual cost of achieving this higher level of energy efficiency is $243 million more than the base case, of which $105 million would come from ratepayers and $138 million from increased out-of-pocket spending by program participants. The increased participant cost assumes the availability of financing, e.g., through the Connecticut Clean Energy Finance and Investment Authority, as well as stricter energy efficiency codes and standards.

By 2022, expanded energy efficiency would save customers $778 million per year in energy, capacity, and RPS costs compared to the base case. With an annual incremental cost of $105 million in energy efficiency program costs and $138 million in participant out-of-pocket costs, customers' annual net savings would be $534 million.

In addition to reducing consumption, the scenario results in lower rates and emissions and increases in-state employment. When customers spend less on energy, they can spend that money on other goods and services, which benefits the Connecticut economy. Based on macroeconomic modeling conducted by the Department of Economic and Community Development for the IRP, each $100 million reduction in net customer energy costs supports or creates 780 in-state jobs.

Because every dollar customers save due to reduced prices means one dollar less paid to power suppliers, the suppliers may retire more capacity, delay the construction of new generation, or charge more for their generating capacity in order to stay in business. The IRP analysis incorporates these effects at least through 2022, with expanded energy efficiency leading to 547 MW more closings in 2016, and with the entry of new combined-cycle generation being delayed from 2022 to 2025.

RENEWABLE ENERGY

Current Law

Connecticut adopted its initial RPS requirement in 1998. It requires electric companies and competitive suppliers to get an increasing proportion of their power from class I resources. They can meet their obligations by buying renewable energy credits (RECs) on the wholesale market. One REC is created from one MWh of qualifying renewable electricity generated in or shipped to New England. If an electric company or competitive supplier does not meet its RPS obligation, it must make an alternative compliance payment of $55/MWh (5.5¢/kwh) for the shortfall.

Since the RPS was established in Connecticut and other states in the region, the Class I renewable resources in New England have grown sufficiently to meet the region's current requirement, with short-term REC prices hovering around $20-$30/MWh during most of the recent year.

Future Renewables Supply

According to the IRP, while the resource potential in the region remains high, particularly for wind power in northern New England, there are many uncertainties in meeting the RPS in the long term. Substantial new transmission investments would be needed to deliver and integrate large additional amounts of remote wind resources. But viable transmission options, their costs, transmission planning processes, and transmission cost allocation rules present issues that are not yet resolved. In addition, the recession has made it increasingly difficult for new renewable energy resources to secure funding. Finally, the future of federal tax credits for renewable energy production is uncertain.

Policy Options

The IRP considers the options of (1) maintaining the current RPS and (2) expanding the definition of Class I resources to include the savings from expanded efficiency programs. The IRP evaluates each option based on environmental performance, costs to Connecticut customers, and in-state job creation.

Maintain Current RPS. The first option considers compliance with the RPS with three levels of Class I development: a low renewables case with very little additional Class I development; the base case, with more than 2,500 MW of projected renewable additions in the region based on extrapolating observed development trends; and a full renewables build-out case in which enough Class I resources (along with necessary transmission expansions) are developed to meet Class I demand in Connecticut and the rest of New England.

Under the base case, the region is short of Class I requirements for 2018 and beyond, with Connecticut paying high REC prices, alternative compliance payments for substantial REC shortfalls and part of the costs of new regional transmission investments.

Under the "full renewables" scenario, the region meets the existing Class I requirement, with REC prices at levels required to support the development of wind, which are significantly lower than the alternative compliance payment. But this scenario would require a large-scale, coordinated, and timely investment in transmission facilities to permit the development of a significant amount of wind power in northern New England. It would also require favorable assumptions regarding the costs of building transmission facilities and the allocation of those costs to Connecticut customers. Achieving this scenario would thus depend on the favorable resolution of many difficult issues that are not directly within the state's
control.

Expanding Resources that Count Towards the RPS

In light of the increasing costs and uncertainties around meeting Connecticut's expanding Class I RPS target and the benefits of energy efficiency spending, the second option considers treating the savings produced by efficiency programs as a Class I resource that could be used to meet up to one quarter of the RPS requirement. According to the IRP, this would produce significant benefits beyond the expanded energy efficiency scenario. Adding flexibility to the Class I requirement would save customers $152 million annually by 2022 compared to the

expanded energy efficiency scenario alone, primarily by reducing the quantity of Class I RECs purchased from renewables and reducing alternative compliance payments. This approach would also reduce the price of RECs from Class I renewables by reducing demand for them.

Compared to the base case, the RPS flexibility policy combined with expanded energy efficiency would save customers $686 million by 2022. Customer rate impacts would also be considerably more favorable than with expanded energy efficiency alone or to the base case. Relative to expanded energy efficiency alone, 2017 rates would be 0.06¢/kWh lower, and 2022 rates would be 0.55¢/kWh lower.
In 2017, rates would be 0.15¢/kWh higher than the base case, but by 2022 rates would be 1.15¢/kWh lower.

Recommendations

The IRP finds that expanded energy efficiency, when allowed to compete for up to a quarter of the Class I requirements, can achieve even more ambitious environmental goals, with lower costs and rates and more in-state jobs for Connecticut. Thus, the plan recommends amending the RPS requirements to realize this opportunity. The IRP recommends that there be future discussion on allowing other resources, such as out-of-region large hydropower, to help meet Class I requirements more flexibly.

COST OF SERVICE GENERATION

Analysis

The IRP presents a scenario in which a new efficient 656 MW gas-fired combined-cycle plant is built in Connecticut in 2017 for a capital cost of $929/kilowatt (2012 dollars, excluding interest during construction) backed by power purchase agreements or other support from Connecticut customers. This scenario examines the value to Connecticut customers of paying the full cost of new conventional generation, receiving its full market value, and doing so before such a resource would have been developed by merchant developers.

The scenario assumes that this type of plant would have $17 per kilowatt per year in fixed operating costs, e.g., property taxes, the same as for other prospective market entrants. On the other hand, it uses a lower (6.7%) average weighted cost of capital, reflecting the allocation of risk to electric customers.

Customers would pay for the plant on a cost-of-service basis. This means that customers, rather than paying market prices for the power, would pay the plant's full capital cost plus fixed operating and maintenance costs over the plant's expected 30-year life. This cost would be recovered through a charge that would apply to people who buy power from competitive suppliers as well as from those who buy power from the electric companies. In exchange, the customers would receive all of the plant's revenues, including any payments for energy and capacity.

Findings and Recommendations

The IRP finds that this scenario is not economical. It states that

> …building new generation always entails assuming risk, but sponsoring a new generation facility well ahead of likely market needs inflates these risks and using a cost-of-service cost recovery model shifts risk onto customers. In addition to the typical risk that any particular plant might not earn enough in the markets to cover its development cost (including a return on investment), recent capacity market rule changes raise the real possibility that a proposed new resource will not qualify for *any* capacity payments during its early years in operation. (emphasis in the original)

With regard to the last point, the IRP describes the minimum offer price rule. This component of the wholesale market rules is designed to prevent and mitigate the exercise of market power, i.e., artificially depressing the capacity price by flooding the market with uneconomic capacity. While the details regarding this new rule and how it would apply to specific market offerings have not yet been fully determined, generally new generation will have to bid a price in the capacity auction as though it did not have a state-sponsored contract. A plant being introduced before it would be economic on a competitive basis might not clear the market and thus might not get paid for capacity. In the worst case, the new cost-of-service generation unit examined by the IRP would not earn capacity revenues until at least 2023, at which time a new merchant unit also would be economic. The plant's total benefits would not exceed its total costs (on a net present value basis) until 2035.

The prospect of cost-service generation is somewhat better when the plant's impact on wholesale energy costs is considered. Adding a 656 MW plant to the market before it is needed reduces wholesale energy costs by $1.6 to $2.1/MWh between 2017 and 2022. This brings the break-even point forward to 2022. In addition, building an efficient gas-fired plant in Connecticut would (1) reduce New England emissions of NOx, SO_2, and

CO_2 and (2) create 2,700 total (direct, indirect, and induced) jobs during the two-year construction period, followed by 100 ongoing jobs over the life of the plant.

The IRP's resource adequacy analysis indicates that new generation is not needed in New England until 2022 or later and not needed specifically in Connecticut until much later. The economics of building cost-of-service generation ahead of need suggests some potential benefits, although nothing strongly positive. Given these findings, the IRP argues that it makes sense to wait until closer to the time of need. Sponsoring new generation should be reconsidered in the next IRP in two years, considering updated information on market conditions at that time. Building a plant that went into operation in 2020 might create benefits (including the reduction of wholesale energy costs) that might outweigh its costs almost immediately.

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