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Impacts of Renewable Energy Subsidies/Incentives on Costs of Achieving Renewables Goals

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As market-based policies such as cap-and-trade and emissions taxes have lost political traction, regulators have emphasized second-best policies such as renewable portfolio standards (RPS) to reduce greenhouse gas (GHG) emissions, the idea being that increasing generation from renewable sources will mean less generation from fossil energy and therefore lower total GHG emissions. Within these second-best policies, regulators have also added more measures to promote specific types of renewable generation or to provide incentives to non-utilities to install or use renewable generation. These policy levers include:

- Direct subsidies from utilities;
- Net metering;
- Feed-in tariffs;
- Tax credits and cash grants from state and federal government; and
- Technology-forcing through mechanisms such as renewable energy standards (RES).

This analysis shows that if the policy goal is to meet a specific target for generation from renewable sources, including additional financial incentives beyond the mandates increases the cost of achieving the desired level of renewable generation.

Introduction

The United States has used various mechanisms to promote renewable energy development, including direct subsidies from utilities, tax policy, and technology mandates. These policies have resulted in a significant increase in the penetration of renewable energy technologies and a corresponding rise in the portion of total electricity supply from renewable energy technologies. This paper examines these policies and quantifies their impacts on energy supply and retail electricity rates.

The first section reviews the various mechanisms that are used in the United States to promote renewable energy technologies. These include:

- Direct subsidies from utilities;
- Net metering;
- Feed-in tariffs;
- Tax credits and cash grants from state and federal government; and
- Technology-forcing through mechanisms such as renewable energy standards.

These mechanisms have different consequences in terms of which entity bears the above-market cost of renewable technologies and the resulting rate impacts. For example, promoting technologies through the tax code reduces the utility's cost of meeting technology-forcing RPS, resulting in lower rates than would otherwise occur and lower penetration of distributed renewable technology and potential investments in energy efficiency. Conversely, causing all of the costs to be incurred by utilities results in higher rates and higher penetration of customer-owned distributed renewable technologies.

The second section describes how we modeled the various strategies and the impacts of alternative policy designs on the penetration of renewable technologies. This analysis uses the N_{ew}ERA model, an integrated computable general equilibrium macro model coupled with a bottom-up electricity model that includes technology-specific generation options.[1] We examine the effects of alternative policy designs in terms of the resulting change in penetration of renewable technologies, penetration of customer-owned distributed renewable energy equipment, electricity rates, tax credits, economic growth, and consumer welfare.

Strategies Used to Promote Renewable Energy Subsidies

2011 was a banner year for the development of renewable energy in the US, and 2012 is expected to also be a strong year. According to the American Wind Energy Association (AWEA), 6.6 GW of wind were installed in 2011 and almost 5 GW have been installed through September 2012, with an additional 8.4 GW under construction.[2] This represents a more than 40% increase over the installed wind base at the end of 2010. Likewise, according to the Solar Energy Industries Association (SEIA), 1.9 GW of solar were installed in 2011 and1.3 GW were installed in the first half of 2012.[3] Currently, there are all sorts of dire predictions from the renewable energy industry regarding the contraction of new renewable generation projects with the end of the 1603 cash grant program and the scheduled termination of the production tax credit (PTC) at the end of 2012.[4] These predictions imply that the amount of federal subsidies have the greatest impact on renewable generation development and not the individual state RPS mandates or the cost of natural gas.

In this section, we briefly review the primary subsidies and other incentives that apply to renewable energy to provide context for our analysis about the economic efficiency of the different approaches.

Technology Forcing

Twenty-nine states have renewable energy standards and 16 states have set-asides within those standards that require some portion of the total renewable energy to be procured from solar or distributed generation (DG) resources.[5] In most states the bulk of the renewable energy, or renewable energy credits (RECS), are being procured by load-serving entities (LSEs) to meet state RPS requirements. Therefore, the bulk of the demand for these resources is created by technology-forcing policies enacted at the state level. However, disentangling the role of technology-forcing policies from utility subsidies and tax policy with respect to the penetration of renewable generation resources is complicated. As discussed later, utility subsidies in the form of rebates and net metering are key drivers of the penetration of DG. Likewise, tax subsidies drive both central station and DG renewable development. The cost of renewable generation would be significantly higher in the absence of the tax subsidies, and this creates a feedback loop to the technology-forcing strategies. A direct feedback loop in several states has companion language in each state's RPS requirements that limit the rate impacts to customers (e.g., Missouri limits rate impacts to no more than 1% in any year). This language acts as a potential circuit breaker to REC acquisition. There is also an indirect feedback loop, as the acceptability of RPS requirements is linked to voter acceptance and hence rate impacts. For example, in California there was an unsuccessful effort to allow the counting of existing large hydro in the calculation of compliance with the 33% RPS standards. The principle justification for the proposed legislation is to reduce rate impacts and the potential adverse impact to economic growth in the state.[6]

Tax Credits & Cash Grants

Two significant tax policies at the federal level effectively reduce the capital cost of renewable generation technologies. The first policy is the investment tax credit (ITC) or PTC. The ITC creates a 30% reduction in the eligible capital cost, while the PTC can apply even more than a 30% reduction depending on the energy production of the renewable generation (whether central station or distributed) over the 10-year horizon of the credit. The PTC is set to expire at the end of 2012 while the investment tax credit is scheduled to sunset at the end of 2016. The second policy is five-year accelerated depreciation.[7] On a net present value basis, these two federal tax policies reduce the capital cost of wind and solar investments on the order of 20-25%.

The cash grant program, Section 1603 credits, expired in 2011 although there is a safe harbor provision that allows certain investments made prior to the end of 2011 to be eligible for the cash grant even if the in-service date is post-2011.[8] One of the arguments for the cash grants is that it is more efficient since some renewable generation owners can avoid complex investment structures needed to otherwise include tax equity to monetize the investment tax credit. However, assessing the impact of the 1603 program is complicated since it is unclear how many of the grants resulted in constructing projects that otherwise would not have been built versus reducing the demand for tax equity. In 2010, when the 1603 program was extended for one year, the cost of the extension was scored at approximately $3 billion. The Office of Management and Budget (OMB) viewed the program cost as both a combination of substituting cash for a reduction in income taxes (time value of money calculation) and an increase in renewable generation supply.[9]

Tax credits for renewable energy are not limited to the federal government. Twenty-four states offer tax credits; Hawaii, for example, offers a 35% tax credit for personal photovoltaic (PV) systems.

Direct Utility Subsidies

Direct utility subsidies have traditionally taken the form of credits for DG installed on the customer's side of the meter. In most jurisdictions these credits have decreased significantly due to a combination of utilities reaching targets for DG and program budgets being exhausted. The need for direct subsidies to entice consumers to install PV has decreased as a result of changes in tax policy, the rapidly declining cost of PV systems, and innovative financing strategies developed by major solar energy companies.[10] From an economic perspective, if system costs continue to decline and utility rates increase (and customers can avoid these increases through net metering), then it is appropriate to continue to adjust these subsidies downward as the economic incentive necessary to encourage customer participation should decrease.

Net Metering

According to DSIRE, 43 states have net metering policies.[11] The policies vary widely across the states with regard to the size of systems allowed, the maximum amount of load allowed under the net metering tariff, interconnection policies, and treatment of generation in excess of loads. The economic benefits of net metering to the owner of the behind-the-meter generation also vary significantly across utility. Customers who incur energy-only rates tend to save more than customers who are demand-metered since net metering does not necessarily reduce peak demand charges. In addition, the structure of the energy rates makes a big difference. Customers who are on time-of-use (TOU) rates tend to save more than customers on flat rates.

Categorization of net metering as a subsidy for DG is controversial. A net metering customer on an energy-only rate can effectively receive transmission and distribution (T&D) services for free (possibly after a nominal installation cost) and not have to pay for either back-up power or for the utility to "store" excess generation until a future time. However, the economic benefits to the utility and other customers in part depend upon how the avoided utility costs are calculated and the associated time frame.

Analysis of Alternative Strategies

Our analysis examines the economic efficiency of alternative strategies and the resulting penetration of renewable generation. Our base case is the current mix of policies with the expiration of the PTC and ITC as scheduled. We then examine the economic impacts of three different strategies:

1. A national RES;
2. A renewable standard achieved via a credit on capital costs; and
3. A combined national RES and localized DG requirement.

In all of our scenarios, we target the same end point with respect to the amount of renewable generation. The focus of our analysis is to examine the economic efficiency of different approaches to increasing the penetration of renewable generation. All of the scenarios required at least the minimum generation additions needed to meet a national renewable target of 20% in 2021. The time horizon for our analysis is 2012 through 2036. The 2021 level of renewable generation reflects a 100% increase above the renewables generation in a Baseline scenario that only includes existing state RPS policies. The scenario that incorporates a credit on capital costs uses the simplifying assumption that the tax credit is in the form of an ITC and not a PTC. Further, all of the scenarios assume that existing renewable subsidies (PTCs and ITCs) are not extended.

Description of the Modeling Approach

We modeled changes in energy prices using our integrated N_{ew}ERA macroeconomic and electricity sector models. We ran the N_{ew}ERA model for a Baseline scenario without any national renewables requirements. Then we ran each of the three scenarios separately by layering them onto the Baseline. For each scenario, we imposed a renewable requirement of 10% beginning in 2015, increasing to 20% in 2021 and maintaining this level throughout the modeling horizon. The method of achieving this level of renewables varies by scenario. Each policy decreased electricity demand and natural gas prices. The lower electricity demand was in response to higher retail electricity prices, while the lower natural gas prices were in response to less demand for natural gas within the electric sector as the renewable requirements ramped up. To avoid confounding the impacts on electricity demand and natural gas prices with changes in the mix of generation resources of the different policies, we locked in the natural gas prices and electricity demand for all cases so that they would be the same as those in the national RES policy.

The model can select from a range of renewable technologies on a regional basis. Technologies include geothermal, on-shore wind, off-shore wind, biomass, landfill gas, central solar, and distributed solar. The model treats distributed solar located behind the customer's meter as a reduction in load. The cost curves for renewable generation were assembled from a number of sources, but primarily from the Energy Information Administration's (EIA's) *Annual Energy Outlook 2012*. The cost curves reflect the forecast of the technology cost over the modeling horizon and reflect anticipated technological advances and economies of scale. In the case of solar, we started with estimates of average installed cost by system size and region based upon costs reported by Lawrence Berkeley National Laboratory in *Tracking the Sun IV*.[12] We assumed costs would decline based upon the target 75% reduction outlined in PV costs in the US Department of Energy's SunShot program.[13]

The model results include retail electric rates that are built up from electric sector costs including generation, capacity, and compliance with state and national renewables programs.

We measure the relative efficiency of achieving the common goal of 20% of generation from renewable resources in 2021 by comparing the present value of incremental electric sector costs. Because we have not allowed electricity demand or natural gas prices to change across the scenarios, and all scenarios achieve the same level of renewables generation, the present value of costs is an indicative measure of the efficiency of meeting the renewables goal.

To Minimize Subsidies/Costs of Incentives, Provide Incentives to Renewable Generation (Not Capacity), Regardless of Technology or Location

By targeting the same level of renewables across the three cases (and by keeping natural gas prices constant and electricity demand constant), we can easily compare the costs of the different means of achieving the renewables target. One method for evaluating the costs of the different policies is to review the subsidies/costs of incentives that are required to achieve the end result. In the national RES policy, the subsidy/cost of incentives is equal to the additional payments made to renewables generators. On a national level, this is equal to the REC price multiplied by the total eligible renewable generation. For the case where the renewables level is met by credits on capital costs, the subsidy/cost of incentives is equal to the investment tax credits that are handed out multiplied by the renewable capacity that receives these subsidies. For the final scenario that combines a national RES with targets for local DG, the subsidy/cost of incentives is equal to the national REC price multiplied by the total eligible renewable generation, plus the region price required to motivate the DG multiplied by the regional DG (summed across all regions). The total level of the subsidies/costs of incentives for each of these cases is summarized in Table 1 for the US as a whole for 2021, the year in which the 20% requirement is first reached.

Table 1: **Required Subsidy/Cost of Incentives to Comply with 20% Renewable Requirement in 2021**

Policy	Subsidy/Cost of Incentives (Billions of 2010$)
National RES	$121
Credit on Capital	$420
National RES/DG	$150

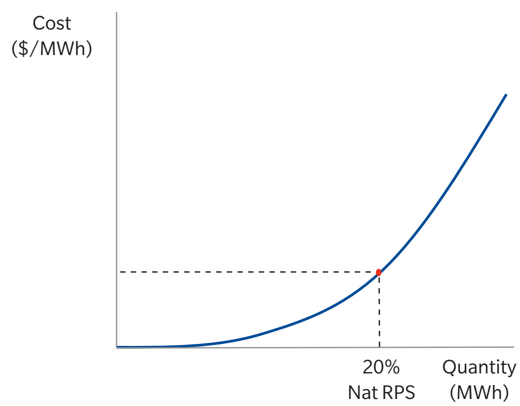
The national RES policy is the most market-based policy and does not pick any winners/losers *within* the renewables category of generation. In addition, the subsidy/cost of incentives is applied consistently with the goal; in other words the subsidy/cost of incentives is provided per unit of generation from renewable sources, and the renewables goal is also a specified level of generation. As a result, the National RES has the smallest subsidy/cost of incentives required to achieve the targeted results, but it is still more than $120 billion in 2021. For context, delivered fuel costs for the electric sector projected for 2021 are about $75 billion.

The credit on capital costs has the highest subsidy/cost of incentives, and this is primarily caused by the mismatch between the subsidy/cost of incentives, which is awarded to capacity, and the goal, which is specified in terms of generation. As a result, higher capital renewables such as biomass take up the subsidy/cost of incentives. While biomass is a dispatchable renewable resource, it has a relatively high heat rate and variable fuel costs that lead to it sometimes not being called upon to generate. Thus, the subsidy/cost of incentives that has brought this capacity online is money that is exceptionally poorly spent.

Lastly, the combination of a national RES and a localized DG requirement has a subsidy/cost of incentives of $150 billion in 2021. The higher cost is due to two factors. The first and most significant is that this policy picks technology types by breaking out a DG requirement. Second, because this requirement has been imposed on a regional basis, this requirement also increases the subsidy/cost of incentives.

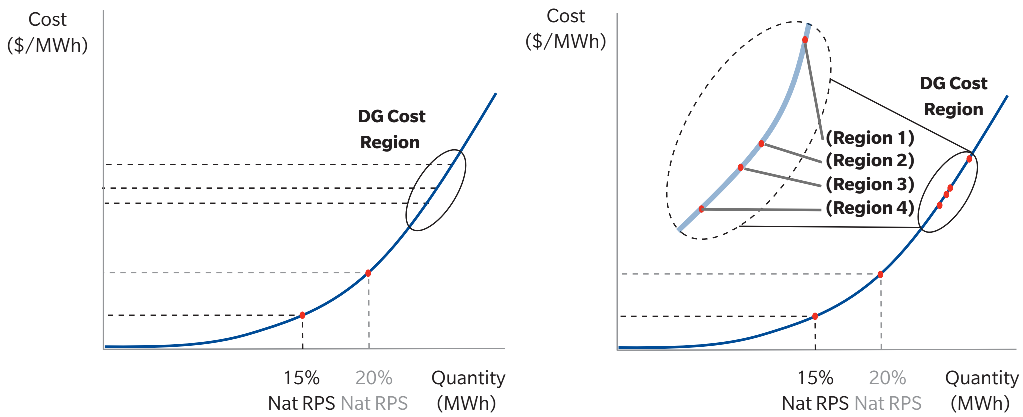
The higher costs associated with the combination of a national RPS and a localized DG requirement relative to the national RPS can be illustrated with a few simple figures. Figure 1 shows a rising marginal supply curve for producing renewables generation. All technologies are placed in order of their costs on the curve; and therefore to understand the compliance costs to meet a National RPS requirement of 20%, we simply move up the curve until we reach the targeted level.

Figure 1. **Illustrative Example of Compliance with National RPS**



The left-hand portion of Figure 2 shows the same rising marginal supply curve for producing renewables generation as in Figure 1. In the case of the combined national RPS and localized DG requirement, we first find the compliance costs for the 15% National RPS in the same way that we did in Figure 1. However, next we need to comply with our assumption of a 5% DG requirement in each region. DG is a higher cost option than many other renewables technologies; therefore, we are forced to skip over these lower-cost technologies that appear in the 15% to 20% range (and at even higher levels as well) under the National RPS to meet the technology-specific DG requirement.

Figure 2. **Illustrative Example of Compliance with National RES/DG**



Further complicating the compliance with the DG requirement is that it is a localized requirement. As seen in right-hand part of Figure 2, some regions have lower costs of DG than others, but again we skip over some of these lower cost options because the policy mandates each region to have the DG and does not allow any trading. The absence of trading and the skipping over of some of the lower cost DG options further increases the costs of the combined National RES/DG policy relative to a National RES policy alone.

In comparing electricity rates there are several important considerations that make comparisons a bit complicated. First, we need to ensure that the rates that we compare across cases are for the same class of ratepayers (we focus on a combined rate for residential and commercial customers as these are the customers that we have assumed install DG in our third scenario). Second, we need to be very clear as to who is incurring the subsidy/cost of incentives. In the case of the National RES, the subsidy/cost of incentives is borne by ratepayers within the electric sector. In the other two cases, it is unclear if the subsidy/cost of incentives would be borne by the government (and hence these costs would be outside of the electric sector and not reflected in electricity rates), or if they would be borne within the electric sector. For our purposes, we present our rates both ways—with subsidies/costs of incentives outside of the electric sector and with those costs staying within the electric sector. It is important to note that even if the costs are borne outside of the electric sector, these are still real costs that would be incurred by everyone. The means by which these costs are distributed could vary widely, but there is "no free lunch" on these costs.

A summary of weighted average US residential/commercial retail rates for the different scenarios is shown in Table 2 for 2021, the first year in which the 20% renewable requirement exists. The analysis shows that when comparing rates in a consistent manner (e.g., where the subsidy/cost of incentives is included in rates or not included in rates), the National RES has the lowest rates in 2021, as expected. The rates for the National RES/DG scenario are higher (when the subsidy/cost of incentives in that case is included in rates),[14] while the Credit on Capital scenario has the highest rates when including the subsidy/cost of incentives in the rates. If the subsidy/cost of incentives was to not be a part of electricity rates then the rates would fall considerably for the two cases where we did this calculation—Credit on Capital and National RES/DG. While the rates would be lowered in these two instances, the subsidy/cost of incentives would need to be funded in some other manner, such as through higher taxes or decreased government services.

Table 2. **Summary of Retail Rates**

Scenario	2021 Electricity Rate (2010¢/kWh)
Subsidy/Cost of Incentives Paid in Electric Rates	
National RES	11.6¢
Credit on Capital	23.4¢
National RES/DG	16.4¢
Subsidy/Cost of Incentives Paid Outside of Electric Rates	
Credit on Capital	11.8¢
National RES/DG	11.8¢

DG Customers Could be Subsidized by Non-DG Customers

Another issue that merits further discussion is the potential for one segment (the non-DG ratepayers) of the residential/commercial ratepayer class to be subsidizing the ratepayer class that owns DG capacity. Effectively, there will be those that install DG and those that do not. We make a few basic assumptions, and then we look at some illustrative consequences. First, we assume that those that install DG are able to size their generating capacity to exactly equal their electricity demand, and hence with net metering would demand no net power from the grid. Second, we assume that electricity bills for these customers with DG are $0.[15] Thus, even though at times these customers are selling power to the grid and at other times are drawing power from the grid and are therefore connected to the grid and benefit from the presence of the grid, these customers are free riding on customers that fully rely upon the grid for their electricity needs. This distortion is further exacerbated if the subsidy/cost of incentives is also borne by the customers that do not install DG capacity.

To evaluate this potential outcome, we calculated electricity rates for the non-DG ratepayers for the National RES/DG scenario. In particular, we look at two potential outcomes to evaluate the consequences for the non-DG customers:

1. DG is installed and owned by the utility and as such all costs and benefits from DG are spread among all residential and commercial ratepayers (we evaluate these rates assuming the subsidy/cost of incentives is within the electric sector and separately where the subsidy/cost of incentives is borne outside the electric sector).
2. DG customers have $0 bills and therefore any fixed costs associated with their connection to the grid is subsidized by those customers without DG (with respect to the subsidy/cost of incentives, when it is included in rates, this is another instance of non-DG customer subsidizing the DG customers).

These weighted average US electricity rates for residential/commercial ratepayers are included in Table 3 for 2021. The difference in the two rows is the level of subsidization (per kWh) that the non-DG ratepayers would be providing to the DG ratepayers.

Table 3. **Retail Rates of Non-DG Customers (2010¢/kWh)**

Scenario	Subsidy/Cost of Incentives in Rates	Subsidy/Cost of Incentives Not in Rates
Utility owns DG	11.7¢	7.4¢
Non-DG customers	16.4¢	11.8¢
Increase in rates (subsidy of DG customers)	**4.7¢**	**4.4¢**

The implications for the possible segmentation of the residential/commercial ratepayer class into those that install DG and those that do not pose some potentially troubling consequences. Since installing DG systems requires significant capital, it is reasonable to assume that these are most likely to be installed primarily by higher-income households. Therefore, lower income ratepayers could be subsidizing higher income ratepayers under some systems that incentivize the installation of DG systems.

The Most Efficient Policy Provides Incentives to Generation and Does Not Pick Technology Winners or Place Limits on Geography

In addition to retail rates, we evaluated the relative efficiency of achieving a 20% share of generation from renewables in 2021. To evaluate the efficiency of each of the three approaches we calculated the total present value of incremental costs within the electric sector for 2015 through 2021 (2015 is the first year that we imposed a renewable requirement, 10%, and 2021 is when we first reach the 20% requirement). In calculating the costs, we only include annual capital charges for the costs attributable to building new units rather than including the full overnight costs in the year in which new builds come online.

Table 4 shows the present value of incremental costs within the electric sector[16] for the Baseline and the three policies that achieve a 20% generation share of renewables in 2021. The National RES policy is the most efficient of the three polies at achieving the 20% renewables target, but still results in more than $30 billion of additional costs over the Baseline, which achieves approximately 13% of generation from renewables generation in 2021. The National RES/DG approach is the next least expensive with incremental costs above the Baseline of nearly $50 billion. Finally, the Credit on Capital approach is the least efficient (most costly policy) by a wide margin with incremental costs above the Baseline of almost $700 billion (or 70% higher costs).

Table 4. **Present Value of Incremental Costs in the Electric Sector (2015-2021), Billions of 2010$**

Policy	PV Incremental Costs	Increase from Baseline (%)
Baseline	$981	
National RES	$1,013	$31.5 (3.2%)
Credit on Capital	$1,664	$683.3 (69.6%)
National RES/DG	$1,028	$47.2 (4.8%)

These results are not surprising since the National RES is the most market-based policy; the addition of the regional DG requirement picks a technology winner (DG) and eliminates some of the efficiencies of trading across regions by adding a regional dimension; and the Credit on Capital is subsidizing capacity and not generation, and therefore inefficiently subsidizes the different renewables technologies.

We should not ignore that each of the three policies adds costs relative to the Baseline and these billions of dollars in costs only increase renewables generation in 2021 from approximately 13% to 20%, so it is also fair to question the goal itself in light of these incremental costs.

Summary and Conclusions

Our analysis supports the basic economic principle that it is most efficient to directly reward the behavior you want to motivate while minimizing any additional constraints outside of those needed to define the general behavior. That is, if the goal is to increase generation from renewable sources, then it is best to reward this activity directly and not indirectly through capacity credits; and it is best to put as few constraints as possible on the type of renewable generation that qualifies to meet the goal. In this analysis, the policy that addresses generation indirectly (Credit on Capital) is far more expensive than the policy that places additional constraints on which type of renewable generation qualifies for the RES policy. This outcome need not hold in all cases. The former raises costs because of the perverse incentives that result; whereas the latter increase costs because it causes the market to install a more expensive technology. Therefore, in this analysis, the perverse incentives are far worse than the technology restrictions, but one can imagine a case where the chosen technology is extremely expensive, in which case the relationship could flip.

We can extend these findings on policy efficiency to a goal of reducing GHG emissions, which may be the unstated goal of policies such as RPS. If the stated environmental goal is to reduce GHG emissions from the electricity sector, rather than to simply generate from renewables, then any form of an RPS/RES will be less efficient than a price on GHG emissions or a cap-and-trade system that controls GHG emissions because the tax and cap-and-trade option directly address GHG emissions and they allow the market complete flexibility in how it wants to reduce emissions. In contrast, the RPS/RES controls generation from renewable sources rather than GHG emissions directly, and by definition, the RPS/RES constrains the policy choices (e.g., nuclear power does not qualify under RPS/RES even though it has zero GHG emissions) and increases the costs.

Notes

[1] Additional details on the N_{ew}ERA model are available at: http://www.nera.com/67_7607.htm.

[2] *Third Quarter 2012 Market Report*, American Wind Energy Association.

[3] *U.S. Solar Market Insight Q2 2012*, Solar Energy Industries Association.

[4] The 1603 program provided a cash grant for 30% of the eligible cost of certain renewable energy generation investments in-lieu of an investment tax credit.

[5] www.dsireusa.org.

[6] In 2012, AB 1771 was introduced to revise the definition of eligible resources. The bill did not make it out of committee due to opposition of environmental groups.

[7] It should be recognized that accelerated depreciation applies to virtually all generation technology investments although the acceleration period depends on the technology and non-renewable generation has a tax depreciation life longer than five years.

[8] As of the end of Q1 2012 it is estimated that 16.5 GW of renewable generation was funded under 1603. Overview and Status Update of the x1603 Program, US Treasury.

[9] Estimated Budget Effects of the "Tax Relief, Unemployment Insurance Reauthorization, And Job Creation Act of 2010", Joint Committee On Taxation, 10 December 2010.

[10] The referred change in tax policy is the removal of the $2,000 tax credit cap on residential PV systems in the Economic Stabilization Act of 2008, which allows residential system owners to take a full 30% federal investment tax credit. The cost of installed PV systems has dropped approximately 33% in real terms over the past five years.

[11] http://www.dsireusa.org/solar/solarpolicyguide/?id=17.

[12] *Tracking the Sun IV An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010*, Barbose, Darghouth, Wiser & Seel, Lawrence Berkeley National Laboratory, September 2011, LBNL-5047E.

[13] SunShot Vision Study, US Department of Energy, February 2012.

[14] The National RES/DG subsidies/costs of incentives that are included or excluded are only those associated with the DG requirements. The subsidy/cost of incentives costs associated with the National RES is always included in rates.

[15] This is a simplifying assumption. Some states charge a nominal fixed charge or have a minimum bill for those customers with DG, but there are no current national standards as to how this might be implemented.

[16] Incremental costs include all fuel and operating costs, and capital costs undertaken during the model horizon. Depreciation on capital investments prior to the first year of the model horizon is not included.

N_{ew}ERA Integrated Model

NERA developed the N_{ew}ERA model to forecast the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant impacts on the entire economy, one needs to use a model that captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The N_{ew}ERA model combines a macroeconomic model with all sectors of the economy (except for the electric sector) with a detailed electric sector model. This combination allows for a complete understanding of the economic impacts of different policies on all sectors of the economy.

The macroeconomic model incorporates all production sectors and final demand of the economy. Policy consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.

The main benefit of the integrated framework is that the electric sector can be modeled in great detail yet through integration the model captures the interactions and feedbacks between all sectors of the economy. Electric technologies can be well represented according to engineering specifications. The integrated modeling approach also provides consistent price responses since all sectors of the economy are modeled. In addition, under this framework we are able to model electricity demand response.

There are great uncertainties about how the US natural gas market will evolve, and the N_{ew}ERA model is designed explicitly to address the key factors affecting future natural gas supply and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on the domestic and international markets, the N_{ew}ERA model includes resource supply curves for US natural gas. The model also accounts for foreign imports and U.S. exports of natural gas, by using a supply (demand) curve for US imports (exports) that represents how the global LNG market price would react to changes in US imports or exports.

The electric sector model is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model determines investments to undertake and unit dispatch. Because the N_{ew}ERA model is an integrated model of the entire US economy, electricity demand can respond to changes in prices and supplies.

The steam coal sector is represented within the N_{ew}ERA model by a series of coal supply curves and a coal transportation matrix. The N_{ew}ERA model represents the domestic and international crude oil and refined petroleum markets.
The N_{ew}ERA model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, disposable income, and changes in "job equivalents" based on labor wage income.

Policy Analysis Capabilities

The N_{ew}ERA model has the capability to evaluate a range of current and proposed policies. Because the NERA team has developed the N_{ew}ERA model, we are intimately familiar with how the model responds to various constraints and therefore are able to logically and effectively represent policies designed by regulators within our model.

As examples of policy capabilities, the N_{ew}ERA model can represent the following policies and types of policies:

- Emission taxes or prices;
- Emission cap-and-trade policy (e.g., Title IV, CSAPR);
- Renewable portfolio standards (state, regional or national);
- Efficiency standards in electric and non-electric sectors
  (e.g., MACT, heat rate standards, CAFE);
- Mandated construction of new builds or retrofits (or requirements to retrofit or retire);
- Financial incentives (e.g., for renewables or for electric vehicles); and
- Low carbon/renewable fuel standards (e.g., LCFS and RFS).

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