

GUEST JUICE

The 33% Solution & Energy Market Impacts

By Arthur O'Donnell

If nothing else, the new state bill to enact a 33 percent renewable portfolio standard—SB1x-2 by Senator Joe Simitian (D-Palo Alto)—resolves a key policy issue: Why, exactly, is California committed to having such a large portion of its energy deliveries come from renewable energy resources?

Many people believe that because the 33 percent mandate was imposed by then-Governor Arnold Schwarzenegger it's a cornerstone of AB 32 implementation—California's climate protection law. Its main justification was thought to be reducing greenhouse gases by crowding regional coal power out of California's energy system purchases. But, the author of the bill has laid out a broader justification for the goals, in which addressing climate change is just a single factor.

The rationale behind the mandate has a significant impact on how the measure would impact regional energy markets, should it become law.

The existing statute imposing the 20 percent renewables portfolio standard goal by 2010 (which utilities still have not achieved) does not even mention greenhouse gases or climate change. Instead, the original renewables portfolio standard was a reaction to natural gas-price volatility during the Western Energy Crisis of 2000-01.

Following passage of AB 32 in 2006, virtually all of California's energy and environmental policy structure was reassessed through the lens of the requirement to reduce state greenhouse gas emissions to 1990 levels by the year 2020. When Schwarzenegger vetoed the first legislative vehicle to expand the goal to 33 percent, that bill was replaced with an executive order clearly framed within the AB 32 context.

One of the primary reasons for a statutory renewables portfolio mandate was to make sure that public power utilities and other retail energy suppliers would be subject to the same requirements as those imposed on regulated electric utilities. That has remained consistent in all the versions of the 33 percent rule, as is the long-term commitment to a more competitive and sustainable energy system.

Now, however, recent amendments to SB1x-2 add: "The program objective shall be to increase, in the near

term, the quantity of California's electricity generated by renewable electrical generation facilities located in this state, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents."

Not specified in the bill, but enunciated by its author, Simitian, are other rationales for the 33 percent mandate:

- Bringing green investment, expertise and jobs to California;
- Improving air quality;
- Protecting customers from price manipulation; and
- Allowing for an American foreign policy based on American values and American interests, rather than energy needs.

Worthy goals.

Intriguing as this last policy pronouncement might be, here we are more concerned with the impacts of the in-state development directive because it helps understand an important aspect of the bill—how it treats the use of renewable energy credits (RECs) from the Western region.

As *Current* readers know, the California Public Utilities Commission, after much delay and many revisions, has finally approved the use of tradable renewable energy credits (T-RECs) from throughout the Western grid, subject to a \$50/MWh price cap and a limit of 25 percent of the existing 20 percent renewables portfolio energy delivery requirement. The CPUC intends to revisit these restrictions after two years.

In the legislative debates over the past three years, union interests and some others argued for eliminating renewables credits for fear that they would flood California and prevent in-state development. Some regional players fear the credits as well, worrying that California would take them and dump unbundled electrons into the Northwest grid, imposing negative energy prices during spring river runs.

SB1x-2 imposes some new limits on out-of-state renewable credits, in the form of a declining schedule of eligibility—starting at 25 percent but dropping to just 10 percent of the compliance need in 2020. In addition, the bill creates a "loading order" for adding renewable resources in which the credits are assigned a third-place

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priority for procurement.

Using renewable credits as a bridge to more in-state development is a sensible approach, and this decreasing amount was adopted as a compromise solution to the in-state/out-of-state debate. Everyone admits how difficult it is to develop any kind of project in California, and transmission constraints will continue to define the market options.

However, this limitation on credits may actually make it more expensive to meet the expanded renewables portfolio standard requirement, while preventing utilities and other sellers from locking in benefits from long-term contracts for tradable credits.

The best reasons for employing credits include the fact that they do not take up transmission capacity and can be scheduled for use at different times than the underlying energy is generated. Tradable credits also provide generation developers with a potential source of predictable revenue beyond the commodity price for electricity, and some developers count on that revenue to make their project financing viable.

But the declining eligibility will drive utilities towards shorter-term deals for credits, increasing the volatility of pricing and reducing certainty for sellers. Uncertainty is a death knell for deals.

Even though the California utilities may now commit to renewable energy credits for compliance, none have brought any REC-only deals forward for commission approval since the commission approved their use in January.

Only Pacific Gas & Electric has won approval for

a transaction involving renewable credits from Alberta wind projects, but that was a power purchase in which the energy is immediately resold locally in Canada, and was up for consideration well before the T-RECs order was signed.

California entities could sign contracts for renewable credits today that would push them well ahead of their still-lagging renewables portfolio standard requirements. But why should they? The commission has shown that it doesn't really intend to enforce the 20 percent minimum purchase requirement.

In addition, the terms of the prospective 33 percent law will allow them to essentially hold steady at 20 percent until December 31, 2016, before a 25 percent mandate ratchets up. Even then, there are so many excuses for non-compliance built into the bill (insufficient transmission and high cost, among them) that the specific milestone dates might be meaningless.

So, my initial assessment of the market impacts of the prospective 33 percent renewables portfolio standard measure suggests a minimal change. Virtually no new development will occur beyond what the utilities are already contracting for until after 2016. Out-of-state developers counting on the California market will find little opportunity for selling renewable credits on a long-term basis.

And we're still left with a gap between policy pronouncements and our ability to achieve the worthy goals expressed by those policies.

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Tradable Renewable Energy Credits

To avoid the fate of Tyrannosaurus Rex, T-RECs—or Tradable Renewable Energy Credits—are touted as a market strategy for avoiding extinctions of four- and two-legged creatures. Tradable RECs represent the “green”—or carbon lite attribute of non-fossil energy supplies. This branding, also known as “green tags,” is bought and sold separately from the renewable unit’s energy output. T-RECs are traded in several states but have been limited in California. A contentious issue is who owns the “green” attribute of renewable projects under contracts signed before renewable energy credits came into being—the renewable generator or the utility holding the contract.