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SPECIAL REPORT

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Clean energy is getting cheaper to generate every day. As worldwide demand for energy continues to grow, governments are concerned about the security of their supply and the potential impact that burning more fossil fuels will have on global warming. As a result, investment in clean energy is running at record levels. Nevertheless, clean energy still isn't economical on its own, meaning that government support remains essential.

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30 Who Will Be Second Solar? Understanding Competition In Solar Panel Manufacturing

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Only a few companies stand out in the incredibly competitive and commoditizing solar panel manufacturing industry, which has several dozen large manufacturers and, reportedly, at least a thousand producers in all. The clear leader is currently First Solar, which has by far the lowest cost structure and highest margins in the industry. As companies try to replicate First Solar's success, the question now becomes, who will be "Second Solar"?



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Mexico will invest \$2.5 billion in wind farms in the Baja California peninsula. It's the latest in a number of projects that President Felipe Calderon has said will help the country meet its target of quadrupling its wind power capacity by the end of his administration. With oil reserves declining and an environment vulnerable to climate change, Mexico is viewing its potential for a strong renewable energy industry to support its economic growth.

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Global Clean Energy Investment Is In The Spotlight Due To Policy Uncertainties

Overview

- Market expansion in the growing and increasingly competitive global clean energy sector is occurring amidst a host of economic, geopolitical, and policy challenges facing the industry, especially related to public sector support of renewable energy and nuclear power generation.
- Policies and regulations appear to be in a state of flux. Recent moves by Spain and the Czech Republic to cut the subsidies applicable to existing operational renewable energy projects demonstrate to us that regulatory risk is assuming greater importance.
- We expect investor interest will remain high as long as incentives remain for global clean energy development. However, we believe governments may not be able to sustain these incentives.

Clean energy is getting cheaper to generate every day. And as worldwide demand for energy continues to grow, governments are concerned about the security of their supply and the potential impact that burning more fossil fuels will have on global warming. As a result, investment in clean energy is running at record levels.

Nevertheless, clean energy still isn't economical on its own, meaning that government support—through subsidies and regulations—remains essential. Standard & Poor's Ratings Services sees a number of credit risks facing issuers in clean energy-related industries. These risks relate to the sustainability of renewable energy incentives and government policies on low-carbon generation, along with transmission capacity constraints and the reliability of some newer technologies. In addition, there are geopolitical concerns arising from political unrest and/or an overreliance on fossil-fuel-producing economies, especially in the Middle East and North Africa.

The global economy will need to figure out a way to meet rising energy

demand and constrain greenhouse gas (GHG) emissions so that global temperature rises do not exceed two degrees Celsius by 2050. The International Energy Agency (IEA) estimates that, to reach those goals, we'll need to invest more than \$30 trillion in energy infrastructure over the next 25 years. According to the Pew Charitable Trusts (*see note 1*), investment in clean power assets alone could reach \$2.3 trillion over this decade. However, that milestone may be difficult to achieve as governments try to cut spending.

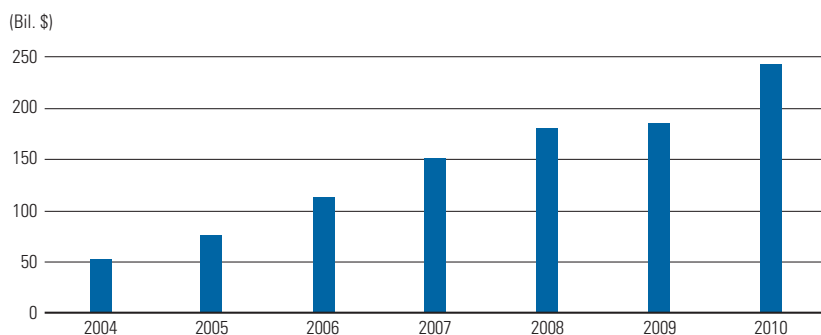
Worldwide Investment In Clean Energy Hits A High

In 2010, global investments in clean energy reached a record level of \$243 billion—up by 30% compared with 2009 (*see chart 1*). Collectively, the EU was the leading recipient of this finance, attracting a total of \$94.4 billion (*see chart 2*). Investments in small-scale solar installations in Germany and Italy, for example, were about double their 2009 level, at \$41.2 billion and \$13.9 billion, respectively.

In Asia, clean energy investment rose 33% to \$82.8 billion. China recorded a similar increase, up 39% to \$54.4 billion, at the same time surpassing the U.S. as the country with the most installed clean energy capacity in megawatts.

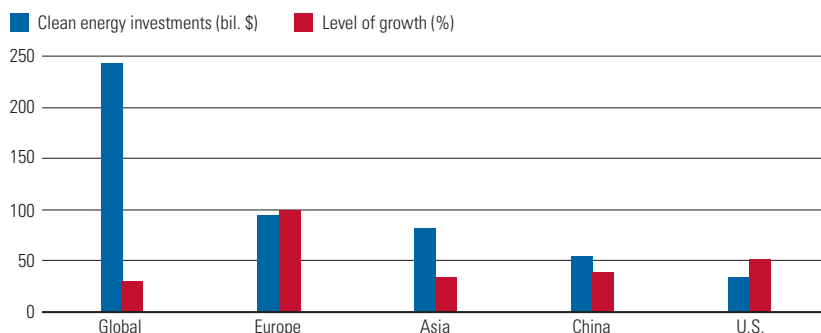
The Americas ranked third in clean energy investment last year, attracting \$65.8 billion. In the U.S., private funding rebounded 51% from its 2009 level to reach \$34 billion. Falling solar technology prices, as we currently observe in the market, could potentially lead to solar power achieving “grid parity”—that is, become competitive with power from traditional fossil fuel sources—in three to five years’ time, in our view. To us, this trend substantially supports the interest in this sector among U.S. utilities (*see “Solar Panel Manufacturers Adapt To Commodity-Like Pricing And Fickle Demand,” in this section*). The public sector has been investing actively as well: At \$8.8 billion per year, overall spending by the U.S. government on

Chart 1 Total Investment In Clean Energy 2004 To 2010



Source: Bloomberg New Energy Finance.
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Chart 2 Global Investment And Annual Growth In Clean Energy 2009 To 2010



Sources: International Energy Agency and The Pew Charitable Trusts.
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efforts to address climate change has almost doubled from the level of 2003, with funding for clean energy technologies outpacing that for scientific research and overseas aid.

However, the market for financing renewable energy in the U.S. is set to change significantly in the years ahead. The U.S. Department of Energy's Loan Guarantee Program, which allows many renewable projects to borrow at Treasury rates, is coming to an end in September 2011. (However, the program will continue to support companies or projects pursuing innovative and commercially unproven clean energy technologies.) The popular 30% Investment Tax Credit cash grant is also set to expire at the end of 2011, although the tax credit itself remains in place until September 2016.

In our opinion, these changes will result in a transformation in renewable energy financing in the U.S., one in which the capital markets will likely play a leading role. We also see insurance-based structures emerging to manage technology and other risks, at least until solar financing becomes established. We think the demand for renewable energy financing will increase sharply as the cost of renewable energy, especially solar power, continues to decline. However, while banks in the U.S. have financed wind and small solar projects, no large utility-scale solar project has yet tapped the capital markets without a guarantee.

State-owned Chinese banks could provide another important source of debt capital. They already support Chinese solar panel manufacturers through cheap loans, while the government offers incentives for land, electricity, and labor costs.

A second transformational element in renewable energy financing could see the tax equity market playing a larger role, following the expiry of the cash grant. Industry participants suggest that to increase the number of tax-efficient investors, master limited partnerships (MLPs) should be allowed to invest in renewable projects. Currently, MLPs can invest only in a few selected asset

classes such as gas pipelines and midstream gas processing plants.

Finally, given the burgeoning market for rooftop residential and commercial solar installations in the U.S. and worldwide, securitization offers a route to finance large solar installation portfolios. This is because one or a few installations would likely be too small an investment to elicit investor interest.

Outside the U.S., growth in clean energy investment has been even sharper in Latin America. In 2010, private clean energy investment in Argentina rose by 568% and in Mexico by 273% compared with 2009—the highest growth rates among G-20 members (a group of 20 major economies, covering 19 countries plus the EU). In Mexico, clean energy project investment totaled \$6 billion in 2010—the highest in the region.

Czech Republic have recently cut subsidies for existing operational renewable energy projects (see “*Why Regulatory Risk Hinders Renewable Energy Projects In Europe*,” in this section). And reduced feed-in tariff (FIT) rates for solar power—that is, the government-mandated price at which utilities are obligated to purchase power from any solar project—could weaken a project's credit quality and, consequently, the levels of installed capacity in the next five to 10 years.

The regulatory approach varies by country and often depends on the structure of the incumbent power sector regime. In the U.K., which has a largely deregulated electricity market, the government is proposing large-scale reforms to provide more incentives for clean energy investment through FITs and a carbon floor price. Meanwhile, Phase III of the EU Emissions Trading

Wind energy remains the favored technology for private investment in the G-20 countries, accounting for 48% of total investments...

Credit Risks Rise As Policymakers Review Their Options

Wind energy remains the favored technology for private investment in the G-20 countries, accounting for 48% of total investments, or \$95 billion in 2009. Worldwide, according to the IEA, generating capacity from clean energy totaled 388 gigawatts (GW) in 2010, aided by 40 GW of wind- and 17 GW of solar-powered installations.

Still, government support remains crucial. In Europe, for instance, solar power projects depend on subsidies for about 85% of their initial revenues. Although the current technological limitations of clean energy systems, such as efficiency, load factor, and natural resource availability, can affect the credit quality of companies and projects operating in the sector, we consider regulatory risk to have a greater impact on creditworthiness. Spain and the

Scheme that starts in 2013 looks likely to impose significant carbon liabilities on some power generators, leading to potentially higher costs for fossil-fuel-burning generators that are contending with higher carbon prices and full auctioning of carbon emission allowances (see “*Utilities Will Feel The Squeeze As Europe Tightens Its Grip On CO2 Emissions In 2013*,” in this section).

Outside the EU, other countries are looking to cut their carbon emissions. Mexico, for instance, has assumed a non-binding goal to reduce to 50% its GHG emissions by 2050 from its current levels. The Mexican government believes renewables and energy efficiency are vital to achieve this goal. Its Energy Sector Program (2007 to 2012) aims to increase by 26% the installed capacity generation through renewables. (For more details, see “*Mexico Has A Bright Future In*

Renewable Energy If It Can Clear Regulatory Hurdles,” on p. 36.)

The U.S. currently represents a stable investment environment with a variety of incentive schemes, according to KPMG (see note 2). California, with its abundant natural resources, has a long history of support for renewable energy and is leading on that front. The California Air Resources Board, under its AB 32 authority, is set to enact regulations to achieve the goal of 33% renewables by 2020. In the Midwest, state-level renewable portfolio standards have put significant momentum behind clean energy generation. We believe this could spur a significant increase in renewable energy investments, especially wind generation capacity. The mandate across these states requires 10% of total energy to be generated from renewables by 2015 and 25% by 2025. (For more information, see “Renewable Energy Mandates Bring Winds Of Change To U.S. Midwest Power Transmission,” in this section.)

A distinct feature of the current market is the trend toward increasing valuations of clean energy producers.

The support for clean and safe energy sources is also strengthening in Japan following the Fukushima nuclear accident on March 11, 2011. We believe the government is likely to implement a new FIT scheme from 2012-2013. In our view, this scheme should provide considerable support for all major clean energy sources including solar, wind, biomass, small-scale hydro, and geothermal power. (See “Japanese Electric Utility Companies—Stalled Energy Strategy Could Hurt Credit Quality,” in this section.)

Australia’s approach to a low-carbon future is starting to take shape. Its power generation fleet is largely coal-based and state-owned, and will require significant investment to update (see “Prospects Dim For Australian Power Generators As Weak Pricing And Carbon Uncertainty

Stifle Outlook,” in this section). Nonetheless, assuming political opposition can be resolved, the current coalition government’s proposals to introduce a carbon tax by July 1, 2012, and then transition to a national emissions trading scheme starting three years later, could accelerate moves to decarbonize the country’s power generation fleet.

On July 10, 2011, prime minister Julia Gillard announced details of the government’s plans. From July next year, 500 of Australia’s biggest polluters will pay a tax of A\$23 (\$24) a tonne on their carbon emissions. A cap-and-trade scheme will replace the fixed tax in 2015. The government plans to use one-half of the carbon tax revenues compensating households for higher electricity and other living costs that polluters pass on. It will allocate a further 40% of these revenues to help businesses and industry adjust to the new regime and switch to cleaner forms of energy.

With this package, Australia aims to cut its carbon emissions by 80% of their 2000 levels by 2050. We understand that the government will invest about A\$10 billion over five years in renewable energy sources such as wind and solar power, and in energy-efficient technologies. Overall, the government believes, these measures should provide the financial incentive to close about 2 GW of Australia’s highest-polluting power stations and promote clean energy investment.

Changing Regulations Could Dampen Investor Interest In Low-Carbon Assets

A distinct feature of the current market is the trend toward increasing valuations of clean energy producers. KPMG predicts

further growth in mergers and acquisitions in this sector over the next 18 months, with transactions at higher EBITDA multiples. Investors are currently willing to pay 3x to 5x EBITDA for renewable energy companies, compared with 3x EBITDA or less in 2009, according to KPMG.

In our view, investor interest will remain high while considerable incentives remain for global clean energy development. However, the policies and regulations appear to be in a state of flux, due to the sometimes conflicting objectives of encouraging renewable energy investment and reducing the burden of subsidies on the taxpayer. Power generation companies and developers often bear the brunt of these policies, requiring substantial capital expenditures (capex) to build out capacity. Without adequate compensation, this capex could weaken their creditworthiness. And while government support mechanisms such as rate-based FITs may underpin sector credit quality to some extent, we believe the sustainability of such mechanisms will continue to face intense scrutiny as governments focus on fiscal austerity. This, combined with the need to conform to climate policies, could force a deceleration of the record growth of investment in clean energy. **CW**

Notes

- (1) “Who’s Winning The Clean Energy Race?,” Pew Charitable Trusts. For more information on PEW and its energy-related activities, see <http://www.pewtrusts.org/>
- (2) “Green Power 2011—The KPMG Renewable Energy M&A Report,” KPMG, June 2011. More information is available at <http://www.kpmg.com/UK/en/IssuesAndInsights/ArticlesPublications/Pages/Green-Power-2011.aspx>

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Renewable Energy Mandates Bring Winds Of Change To U.S. Midwest Power Transmission

Renewable resources are a growing part of the fuel mix at electricity-generation facilities in the U.S., and nowhere is their impact more evident than in the massive wind corridor running down the middle of the country. From North Dakota to Texas, state-level renewable portfolio standards (RPS) and the potential for a federal renewable energy standard have put significant momentum behind renewables—particularly wind.

The Midwest Reliability Organization, the Southwest Power Pool, and the Electric Reliability Council of Texas have proposed the addition of more than 90,000 megawatts (MW) of wind capacity through 2019, on top of the 20,000 MW that exist now (*see chart 2*). And though not all of this conceptual

capacity will likely come to fruition, the size of these proposals is significant compared with the current total operating generation capacity of about 270,000 MW in these regions (*see note 1*).

The Midwest Independent System Operator (MISO) is evaluating the impact of integrating such a large, intermittent resource into the grid. Its concern is that replacing dispatchable generation sources—such as coal units—with variable resources will make power prices much more volatile. In fact, because of uncertainties about the reliability of wind, MISO includes only 12.6% of wind's megawatt capacity when calculating its reserve margin (the amount of unused available capability of an electric power system compared with its total capability)

Overview

- The U.S. Midwest is the windiest part of the country, and could be a huge source of electricity generation that helps states achieve their renewable energy mandates (*see chart 1*).
- Getting that electricity to population centers will require building billions of dollars worth of new transmission lines.
- Several issues may complicate the new construction, including questions about wind power's cost effectiveness and how participants will split the costs.

(see note 2). Moreover, because the wind typically blows hardest in remote regions, utilities would need to spend billions of dollars on the infrastructure necessary to transmit electricity from these areas to population centers. Although high-voltage transmission lines can significantly improve wind's economic prospects, there's significant opposition in communities through which these lines must pass.

Renewable developers and transmission builders face a conundrum: Why invest in renewables if there is insufficient transmission, and why invest in transmission if the resource is unpredictable? We think these questions merit consideration because of their credit implications for power companies. On one hand, a substantial wind build-out will likely hurt the creditworthiness of unregulated generators in the Midwest. On the other, rate-based transmission projects will benefit the credit quality of regulated transmission companies.

Thus far, transmission of power across the grid is done very economically, accounting for just about 7% of the cost of electricity nationally (see note 3). However, these costs will increase as distant renewables are added to the grid. As a result, cost allocation has become a contentious issue among communities (and utilities) who believe they will end up paying a disproportionately higher amount for the lines without receiving commensurate benefits. Until a blackout occurs, reliability remains a rather amorphous concept compared to the more tangible economic benefits of cheaper power.

Renewable Portfolio Standards Are Spurring Growth

Because of state RPS requirements (see table 1) and the potential for a federal renewable energy standard (RES), investments in renewable resources, particularly wind generation, have gained momentum. According to the Midwest Regional Generation Outlet Study (RGOS), which takes into account the renewable mandates of states within the study's footprint, such mandates now total about 25,000 MW. For reference,

MISO currently has about 7,540 MW of renewable generation in operation.

Renewable studies in the Midwest underscore the need for more transmission (see table 2). For instance, the RGOS estimates that a 20% federal RES standard would require the integration of about 41,000 MW. This would entail a significant transmission build-out.

Excluding Transmission Costs, Wind Is Cost Competitive In The Upper Midwest

While the cost of solar photovoltaic generation is rapidly declining (see note 4), wind power is already competitive in the Midwest. According to a Brattle Group study (see note 5), excluding transmission cost differences, wind is comparable in cost to conventional power in the Upper Midwest. Our levelized cost of energy (LCOE) analysis, which covers a 30-year period, is consistent with that conclusion (see table 3).

The key to cost-effective wind-generation is the ability to achieve a high ratio of average actual use to available capacity, or "capacity factor." Excluding transmission costs, wind generation is competitive at a levelized natural gas price of \$5.5 per million cubic feet and a capacity factor of about 40%—because of high-quality wind resources, this is available in many parts of the Midwest. Still, expectations for low natural gas prices, at least through 2016, due to growing production from the enormous shale gas plays around the country pose a significant risk to new wind generation projects.

However, a combination of higher natural gas prices, the continuation of production tax credits (PTC) benefits (see note 6), and the levy of some form of carbon costs on natural gas generation (or, alternatively, renewable energy certificate[REC] benefits for wind generation) would be necessary to support the expansion of transmission for wind generation.

While the cost of solar photovoltaic generation is rapidly declining, wind power is already competitive in the Midwest.

Table 1 Summary Of Renewable Portfolio Standard (RPS) Requirements

State	RPS requirements	Remarks
Iowa	105 megawatts	2% by 2011
Illinois	25% by 2025	
Indiana	No RPS	
Kentucky	No RPS	
Michigan	10% by 2015	
Minnesota	25% by 2025	30% by 2020 for Xcel Energy
Missouri	15% by 2021	
North Dakota	10% by 2015	RPS goal (not a mandate)
Nebraska	No RPS	
Ohio	25% by 2025	50% from within state
South Dakota	10% by 2015	RPS goal (not a mandate)
Wisconsin	10% by 2015	20% by 2020; 25% by 2025

Source: Standard & Poor's.

One way to reduce transmission costs is to overbuild generation capacity. For instance, overbuilding wind generation capacity by 20% (e.g., building 1,200 MW of capacity to supply a 1,000-MW double-circuit transmission line) could increase capacity loading to about 55%. Overbuilding reduces per—megawatt hour (MWh) transmission costs. However, this approach can have unintended consequences for the remaining generating assets in the system.

The Wind Blows Hardest When It's Needed The Least

While average capacity factors determine how much electricity must be gen-

erated to recover the upfront capital costs of wind power projects, net revenues also depend on the price of electricity when the wind is blowing. In other words, the capacity value of wind assets reflects how closely wind output tracks the system's overall load.

Because wind output tends to be disproportionately higher in off-peak periods (*see note 7*), it typically correlates poorly with the overall system load—which increases the variability of demand on the rest of the system. The larger ratio of peak to off-peak demand causes higher cycling of other generation resources, which must ramp up to meet the peak loads and then ramp

Table 2 Transmission Studies In The Midwest

	Region	Line-miles	Renewable integration (gigawatts)	Cost range (bil. \$)
Regional generation outlet study (Aug. 2009)	Midwest independent system operator	5,000–7,500	25	17–23
Strategic midwest area renewable study (Sept. 2010)	Midwest independent system operator	7,500–8,500	57	24–26
CapX 2020 (Phase 1)	Upper Midwest	750	4–6	2

Source: Standard & Poor's.

Table 3 Levelized Cost Of Energy (LCOE) Scenario Comparison

Assumptions	—Natural gas combined-cycle turbine*—				—Wind†—	
Natural gas (\$/Mcf)	5.5	5.5	6.5	7.5		
Carbon price (\$/ton)	0	15	0	15		
Wind capacity factors (%)					25	40
Capital costs						
Capital cost (\$/kilowatt)	1,000	1,000	1,000	1,000	2,200	2,200
Capital recovery through PTC (\$/kW)	0	0	0	0	(275)	(440)
Net after-tax capital cost (\$/kilowatt)	1,000	1,000	1,000	1,000	1,925	1,760
Discounted value of MWh generation	76,888	76,888	76,888	76,888	24,908	39,852
LCOE—capital cost (\$/MWh)	13.01	13.01	13.01	13.01	77.28	44.16
Operating expenses						
Fuel costs (\$/MWh)	39.6	39.6	45.5	52.5	0	0
Carbon cost (\$/MWh)	0	6.75	0	6.75	0	0
Variable O&M (\$/MWh)	2.5	2.50	2.50	2.50	0	0
Fixed O&M (\$/MWh)	3.81	3.81	3.81	3.81	17.62	11.01
LCOE—O&M total (\$/MWh)	45.91	52.66	58.56	58.81	17.62	11.01
LCOE—generation cost (\$/MWh)	58.91	65.66	64.81	78.56	94.90	55.17
Without PTC					105.95	66.22

*Depreciated over 20 years; 60% capacity factor; fixed costs: \$20 per kilowatt-year. †Accelerated depreciation over five years; fixed costs: \$30 per kilowatt-year, PTCs over 10 years. PTC—Production tax credits. Mcf—Million cubic feet. MWh—Megawatt-hour. O&M—Operating and maintenance.

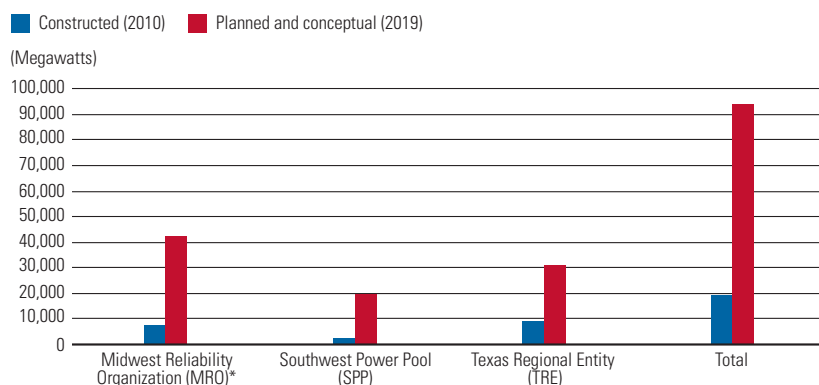
Table 4 Estimated Transmission Spending Of Select Companies

(Mil. \$)	2011f	2012f	2013f	2014f
ITC Holdings Corp.	560–640	800–900	800–900	800–900
Xcel Energy Inc.	450	705	960	865
MidAmerican Energy Holdings*	597	737	1,138	N.A.

*For MidAmerican, we've averaged spending over three years by subtracting generation and distribution spending from total capital spending. Also, these are total transmission commitments; not all projects for these companies are confined to the Midwest. f—Forecast. N.A.—Not available.

Source: Standard & Poor's.

Wind Nameplate Capacity

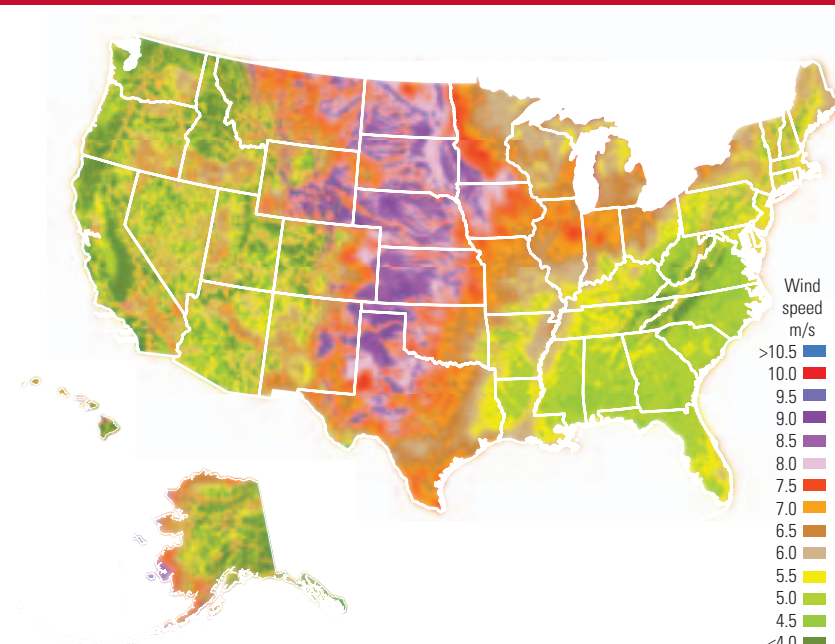


*The MRO and MISO areas overlap, but the MRO includes parts of Canada and the U.S. that are outside of the MISO.

Source: North American Electric Reliability Corp. Long-Term Reliability Report (2010).

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United States Annual Average Wind Speed At 80 Meters



Source: U.S. Dept. of Energy/National Renewable Energy Laboratory.

© Standard & Poor's 2011.

down further during off-peak periods. This greater cycling generally raises the system's overall generation costs.

In essence, increasing wind capacity affects the rest of the generating assets by reducing demand for the rest of the system. For instance, when treating the generation capacity of other resources as fixed, combined-cycle gas turbines, which have higher marginal costs than coal or nuclear units, are the most suitable resources to dial back in the short term as wind output increases. However, in the long term, the relatively lower start-up and cycling costs of these turbines compared with coal-fired units make them a more suitable complement to wind generation. Thus, the addition of wind resources would eventually displace coal-fired assets and force the retirement of older, inefficient coal plants.

On a related note, incidents of negative off-peak pricing—when sellers pay buyers to take the power they are producing—are increasing in many wind-dominated areas, such as the Midwest, the Electric Reliability Council of Texas (ERCOT) West, and the Mid-Columbia region in the Northwest (see note 8). In wholesale power markets, this normally happens when base-load plants that have high restarting costs opt to pay to keep supplying power during off-peak hours instead of shutting down. However, negative pricing may also occur in regions where wind generation dominates. Wind generators earn PTC and REC benefits as part of their revenues but have to forego these revenues when their turbines aren't running. With practically no variable costs, wind generators could generate electricity under negative pricing scenarios because the combined value of REC and PTC benefits would make it economical to do so. Therefore, wind generators need to be paid to shut down production. Incidents of negative pricing are more prevalent in regions where transmission limitations prevent the export of wind generation.

Finally, because they are more variable than traditional power sources, renewable resources require greater supervision and control. On June 1,

2011, MISO started an initiative under which renewable resources can participate in its economic dispatch regime as a dispatchable intermittent resource (DIR). This initiative allows for the automatic dispatch of variable resources, such as wind, up to a forecast limit based on an offer price and system conditions. DIR status will enable wind generators to receive dispatch instructions (rather than be manually curtailed) by the regional transmission organization when transmission constraints limit renewable energy genera-

tion from reaching the broader market. Whether such initiatives can make wind generation more predictable remains to be seen.

In the Midwest, increasing wind capacity is negatively affecting companies such as Edison International and Exelon Corp., which have significant base-load generation capacity in the PJM West region. Edison International has about 5,175 MW of coal power in Illinois, while Exelon has about 10,500 MW of capacity in the rest of the pool area of the PJM, mostly in northern

Illinois. In addition, Ameren Generation has nearly 6,000 MW of coal- and gas-fired capacity in the MISO area. Construction of new transmission lines, however, could give these companies to markets in the East.

More Transmission Spending Appears Likely...

Because renewable mandates within the footprint of the RGOS total about 25,000 MW, a transmission build-out appears inevitable. It only remains to be seen how it will take shape.

MISO'S Multi-Value Approach

For several years, Midwest Independent System Operator (MISO) required a generator seeking to connect with the transmission system of a MISO member to pay up front for the entire cost of any needed network upgrades, although the generator could later recover 50% of those costs. However, confronted with massive wind generation being planned in its relatively unpopulated northwestern zones, MISO developed an interim fix. The new approach repaid generators only 10% of the costs of network upgrades to facilities rated at 345 kV or above and none of the costs for upgrades to lower-voltage facilities.

Later efforts to develop a more permanent solution resulted in a new proposal—the multi-value project (MVP). The MISO plans to consider MVP status on a few “starter” projects, which MISO characterizes as lines that are compatible with each of its three RGOS plans. The MVP would grant regionally socialized cost-allocation treatment to these projects

To qualify as an MVP, a project must meet at least one of three criteria. The first one is that the project be developed through the MISO's transmission planning process and be aimed at delivering energy to support energy policy mandates in a manner that is more reliable or economic than other alternatives. Criterion two is that the project addresses at least one transmission issue associated with a projected reliability violation and at least one economics-based transmission issue that provides economic value across multiple pricing zones, conditioned on the project's cost not exceeding the financial benefits. Alternatively, the project should provide multiple types of economic value across multiple pricing zones at a total cost that does not exceed financially quantifiable benefits.

The Southwest Power Pool (SPP) has implemented a similar approach that FERC approved in June 2010. Under its highway/byway methodology, SPP will allocate the costs of transmission projects based on voltage level: The cost of extra-high-voltage facilities (300 kV and above) would be fully allocated regionally; “mid-tier” facilities (above 100 kV and below 300 kV)

would be allocated one-third regionally and two-thirds to the zone; and low-voltage facilities (100 kV and below) would be fully allocated to the zone. The new way of charging for transmission marks a shift away from reliability-driven planning toward one that takes into account economic opportunities and state and federal energy policies.

Both of the proposals have drawn fire from several utility members who say the new approach to planning would punish some states while unjustifiably rewarding others. Moreover, an amendment to the American Clean Energy Leadership Act (called the Corker Amendment) requires that “any rates affected by the cost allocation methodology, shall be just, reasonable, and not unduly discriminatory or preferential.” Critics argue that by requiring that costs be allocated only to those parties for which the benefits can be measured, the amendment fails to recognize the immeasurable benefits that a more robust grid provides to the non-direct beneficiaries.

MISO and the SPP maintain that their approaches allocate new transmission project costs to those that use and benefit from the new facilities. These regional transmission organizations have argued that their proposals comply with the Corker amendment in that costs allocated to parties are roughly commensurate with the benefits that parties receive. Still, the amendment raises the bar for interstate transmission lines to receive cost allocation treatment.

Still, a number of questions need to be addressed. The most common criticism is that FERC's cost allocation schemes may not recognize that public policy requirements are not consistent among affected states. For instance, what if states adopt differing RPS standards by percentage, or by qualifying energy source? What if states have alternative standards, such as demand reduction in lieu of renewable resources, or meet the renewable minimum thresholds with local resources that do not require comparable levels of transmission as needed by other states in the region, etc.?

Historically, plants in the Midwest have been near load centers and required smaller 345-kilovolt (kV) connections. Industry experts believe that a double-circuit 345-kV line will support current state mandates within the Midwest footprint. However, industry experts also believe that if the government does implement a renewable energy standard, a 765-kV line would be more appropriate because higher-voltage lines have more capacity, lower line losses, and require smaller rights-of-way than double-circuit 345-kV lines. Still, transmission projects in the Midwest will likely proceed with a 345-kV configuration, because only those projects that are necessary to improve current reliability are getting the green light. Because of local opposition, the implementation of more aggressive transmission build-outs that anticipate future needs has been more difficult.

We believe continued expansion in the use of renewable energy sources will benefit transmission owners in the Midwest. However, placing additional lines with larger rights-of-way could prove difficult until the federal government implements a renewable energy standard. Even so, several companies in the Midwest have significant transmission spending plans (*see table 4*). In addition, Ameren Transmission Co. expects to spend a modest \$265 million through 2015 and other regional companies, like American Transmission, have transmission plans in Wisconsin, Michigan, and Minnesota.

The most conspicuous project in the Midwest is ITC Holdings' 3,000-mile, 765-kV Green Power Express, which will total roughly \$10 billion to \$12 billion. When fully built, the project will connect about 12,000 MW of wind generation to the Midwest's existing grid. The Federal Energy Regulatory Commission (FERC) granted Green Power an overall 12.38% return on equity. Ameren Transmission Co.'s Grand Rivers initiative, while not nearly as big, still represents a 10- to 15-year, \$3 billion investment. Phase I consists of four 345-kV projects, costing an estimated \$1.3 billion, and should relieve

congestion as well as facilitate the integration of renewables for RPS purposes.

...But Tough Questions About Cost Allocation Remain

The debates about allocating development costs are particularly thorny in the Midwest, precisely because, net of transmission costs, wind is competitive with gas-fired generation in the region. Advocates for renewables argue that transmission development costs should be spread as widely as possible to ease the connection of distant resources to the grid to meet RPS mandates. However, opponents argue that uniform recovery of costs from all participants in a market area masks the delivered costs of power from renewables, and therefore distorts the generation and consumption incentives of different generation resources.

While FERC has proposed certain broad principles as part of its pending transmission planning and pricing rule-making, many independent system operators (ISO) and regional transmission organizations have developed their own approaches to allocate the costs of new transmission projects among various stakeholders. In some regions, including the PJM Interconnection and the New York ISO, FERC has approved participant funding methodologies that require the developer to assume most of those costs, while in the Southwest Power Pool and the California ISO, it has allowed participants to spread those costs more broadly through variations on "postage stamp" rates, where transmission costs are recovered uniformly from all parties in a defined market area (*see "What's In The Way Of Expanding Electric Transmission In The PJM Interconnection?" published on RatingsDirect on the Global Credit Portal on June 3, 2011*).

In December 2010, FERC approved MISO's multivalued project (MVP) approach, which requires projects to meet at least one of three criteria (*see sidebar*). All the costs for qualified MVPs would be allocated to the entire load in MISO on a postage stamp basis,

reflecting these projects' regional nature. MISO may still need to modify its proposal to conform with FERC's pending RM10-23 ruling.

Renewable Power Is Poised To Expand

Given the state RPS mandates and recent proposals in the Midwest, we believe significant development of renewable power generation in the region is likely—and a related transmission build-out would then be inevitable. However, the parties involved still need to resolve the sticky issue of how to split the costs. While organizations such as MISO have taken steps to do so (*see sidebar*), we expect the path to be rocky—many projects will face delays, and some may derail altogether.

The experience of Spain, where wind contributes nearly 15% of overall power generation, provides some insight into how the process may unfold here. On Nov. 9, 2009, Spain's wind farms generated enough energy to meet 43% of demand. Yet, on June 26, 2009, wind generation covered only 1% of demand. The country has partly miti-

gated the variability of wind generation by creating a larger, integrated market through transmission interconnections with France, Portugal, and Morocco. In the longer term, Spain expects to use wind generation for off-peak activities like pumped storage hydropower and charging of electric vehicles batteries.

Managing a U.S. grid fed by an increasing amount of variable renewable power is tantamount to a high-wire balancing act. For now, Midwest states appear committed to their RPS mandates; less certain is what kind of transmission infrastructure will eventually emerge. The answer is, well, blowin' in the wind. **CW**

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Renewable Energy

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Notes

- (1) Because it is a variable resource, wind has relatively poor capacity factors. Thus, nameplate capacity is much higher relative to actual production.
- (2) Northeast Power Coordinating Council includes 21.1% of its wind nameplate capacity; Western Electricity Coordinating Council, 17.1%; and the SPP 15%; Reliability First Corp., 12.6%; and ERCOT includes just 8.7% of its wind nameplate capacity.
- (3) "Michigan Unplugged—The Case For Shared Investments In Regional Transmission Projects" - Anderson Economic Group (June 2011).
- (4) We believe that as costs of solar panels decline, solar PV can offer substantial benefits that wind cannot provide. These benefits include availability during peak hours and the fact that rooftop PV does not need transmission.
- (5) "Transmission Super Highways: Assessing the Potential Benefits of Extra-High-Voltage Transmission Overlays in the Midwest" (The Brattle Group, March 2009).
- (6) We assumed PTC benefits for 10 years in our analysis. Also, while REC prices in various markets have been volatile, in the West (which is a relatively stable market for RECs), prices have ranged between \$4 and \$7 per MWh.
- (7) As an exogenous source, wind generation tends to rotate the load curve clockwise.
- (8) The wind effect on off-peak prices is evident in the Mid-Columbia region where, in a controversial move, the Bonneville Power Administration has curtailed wind generation to make room for excess hydropower.

Solar Panel Manufacturers Adapt To Commodity-Like Pricing And Fickle Demand

Overview

- Solar panel prices have declined dramatically as Chinese and Taiwanese manufacturers have come to dominate, but substantial oversupply exists that will likely result in industry consolidation.
- Some manufacturers are managing this situation by integrating both forward and backward.
- Government subsidies in some form are still needed although grid parity is closer than many expected even a year ago.
- We expect solar panel manufacturers to remain speculative grade until grid parity is reached.

Solar power, and by extension the solar panel manufacturing industry, both have enormous growth potential. Falling solar panel prices have sparked tremendous interest in solar power among utilities in the U.S. and Europe in the past few years. And we believe that the much-anticipated grid parity—when solar power becomes competitive with other sources (grid power at the retail level and gas plants at the wholesale level)—could occur in about three years. However, in view of the enormous business risks that the panel manufacturing industry faces, we believe that until grid parity is reached, solar panel manufacturers will largely be limited to speculative-grade credit quality.

While Standard & Poor's Ratings Services currently has only a few public ratings outstanding in this industry, we have analyzed a much larger number of companies, including our portfolio of private ratings and the evaluations we have performed under the U.S. Department of Energy Loan Guarantee Program. We expect that the consolidation in the panel manufacturing industry and the exit of high-cost manufacturers, which failed to materialize as in 2009 contrary to widely held expectations, is likely to occur in 2011 and 2012.

The Solar Panel Manufacturing Industry Contended With A Slew Of Variables in 2010

The solar power industry saw important developments in 2010 in almost every aspect of competition—strong demand growth, policy uncertainty, falling prices, the rise of Chinese and Taiwanese manufacturers, and new thin film producers. After 2009, when demand of 7.2 gigawatts (GW) represented only 24% growth (due to the global recession), installations in 2010 grew 141% to 17.5 GW. Three markets that stood out during 2010 were Germany (7.3 GW), Italy (3.85 GW), and the Czech Republic (1.2 GW), all with the support of strong feed-in tariffs (FIT). (A FIT is a government-mandated price at which utilities are obligated to purchase power from any solar project.)

In Germany, project internal rates of return remained strong despite cuts in the FIT (including a special mid-year cut in July 2010) because of the concurrent fall in panel and component prices. This trend of lower component prices also made Italy and the Czech Republic, which have high FITs, extremely attractive markets. At the same time, the unexpected surge in demand in Italy and the Czech Republic, and the consequent policy developments in these countries, also reflect the vulnerability of demand to policy risks.

China boosts crystalline silicon capacity and thin-film production increases

Crystalline Silicon (C-Si) made up 83% of 2010 cell production (87% including SunPower Corp.'s mono C-Si), an increase from 77% (83%) in 2009. As a

result, 2010 was the first time since 2005 that the thin-film market share declined (even though production rose 63%, led by copper indium gallium selenide). This was mainly because of the massive increase in C-Si capacity in China and Taiwan, as well as falling polysilicon prices, also driven by Asian capacity additions.

China and Taiwan dominate C-Si market as the pace of commoditization quickens

Given that C-Si technology is fairly standardized, and with price being the all-important factor, China and Taiwan have emerged as dominant centers of production over the years, with a combined market share of about 60%, up from 50% in 2009. Key to this dominance is access to plentiful, low-cost capital from state-owned Chinese banks (partly a response to the global financial crisis) that has allowed Chinese companies to emerge as leading low-cost producers. Producers from China and Taiwan account for nine of the top 15 cell producers. This growth is also responsible for the current substantial overcapacity in the industry supply chain.

More importantly, top Chinese companies are now considered eminently "bankable." This is an important change from a few years ago that makes the growth in Chinese capacity all the more meaningful in competitive terms. Bankable producers are those that have a sufficient track record of quality, performance, and execution such that banks feel comfortable lending to projects that use their panels. In fact, a number of European and Japanese companies now use Chinese factories to manufacture panels sold under their brand names, and production capacity in these higher-cost countries has shut down or frozen with no growth. Other large production centers in Asia include Malaysia (First Solar Inc., Q-Cells SE) and the Philippines (SunPower Corp.), with growth starting in Korea as well.

Panel Prices Have Resumed Their Decline After Stability In The Second Half of 2010

Panel prices began to collapse starting in the third quarter of 2008 (*see chart 1*) and continued to decline sharply in 2010,

more than keeping pace with FIT subsidy cuts. This was partly because of rising production capacity but also resulted from the falling price of polysilicon (which has dropped to about \$40 to \$50 per kilogram (kg) from as high as \$450 per kg in 2008, with forecasts for as low as \$25 per kg by the end of 2011). Tier 1 Chinese C-Si module prices declined to about \$1.75 per watt-peak (Wp) in 2010 from about \$2.25 per Wp on average in 2009.

The second half of 2010 was a period of stable to moderately rising panel prices as demand growth outpaced supply due to the still-ongoing capacity build-out. However, declines have commenced once again in 2011 as more capacity has come online and because demand growth has weakened. All indications are that the pace of declines is accelerating in the second quarter of 2011, and industry participants have forecast panel prices of \$1.00 to \$1.20 per Wp by year-end 2011.

We believe that a long-term trend of falling panel prices has set in. Although excess capacity, especially from low-cost Chinese producers, is a key factor in current declines, we believe this trend is also fundamental because it reflects the industry imperative to achieve grid parity and the ability of economies of scale to bring down unit production costs. Volatility in polysilicon prices could cause fluctuations, as could, more importantly, variable demand. For example, prices could fall sharply if Germany or Italy imposes a cap or sharply reduces subsidies. Prices could rise if China or India adopts more aggressive solar subsidy policies or if U.S. demand grows rapidly. However, any rise in panel prices is likely to be temporary due to the ease with which manufacturers can add new capacity.

First Solar was selling its modules at a hefty discount compared with the other top panel producers in 2007 and 2008 (*see chart 1*). While this partly reflected the sharp volatility seen in polysilicon prices and First Solar's strategy of contracting for its output two to three years ahead, it was also partly a conscious strategy to drive volume growth. The resulting high capacity utilization rates drove deeper cost reductions. When the market turned and C-Si panel prices

dropped steeply, First Solar saw average selling price declines that were much less than did other manufacturers. First Solar, however, will always sell at a slightly lower average selling price because its lower efficiency implies the need for a larger number of panels for the same megawatt (MW) capacity. The additional land, inverters, panel racks, wiring, and labor costs together create higher balance-of-system costs for First Solar plants. Estimates for the discount First Solar must take are generally about 15 cents per Wp (some calculate it to be as high as 25 cents) but are falling as the company reduces its balance-of-system costs. SunPower's average selling prices are higher because the company only discloses prices for the entire system, including labor and balance-of-system costs.

midst of another bout of declines as FIT cuts in Italy and Germany leave the industry with significant unsold inventories and substantial excess capacity for the foreseeable future, and we do not currently see any other new market emerging.

Spain offers perhaps the best example of policy-driven volatility. It probably has the most days of sun in Europe, augmented by a generous FIT. This resulted in very high project internal rates of return and a massive spike in demand. Installations increased to 2.6 GW in 2008—50% of global demand—from just 35 MW in 2005. This spike caused a supply-demand imbalance and drove up panel and polysilicon prices because the industry was still young, and Chinese manufacturers had not yet gained a dominant position as they do today. Spain then announced a major

responsible for approving grid interconnections received claims for an astonishing 5 GW of installations compared with just 620 MW in 2009. The final number is still unclear, with estimates varying between 2.5 GW and 5 GW. The 17.5-GW global market estimate for 2010 assumes 3.85 GW in Italy.

This growth in installation led to a political backlash in Italy, which announced a new policy in April 2011 that institutes a cap but nevertheless allows for Italy to remain a large market. From May 31, 2011, to Dec. 31, 2016, the cumulative cap on demand is 23 GW, and there is also a cap on the annual subsidy cost. Germany has best implemented the FIT scheme in our view, with a steady annual decline in FIT that is linked to installed capacity. Project economics and panel prices, in turn, determine installed capacity.

Europe is the largest end market, given the attractive FIT regime in many countries, and accounted for almost 80% of global demand in 2010.

Demand Growth Remains Strong—But Policy Changes Can Cause Large Swings

Demand growth has been strong during the past several years (*see chart 2*) and falling prices will tend to improve demand in newer markets as solar economics improve. However, the market is highly concentrated, with a handful of countries accounting for most global demand. Although the magnitude of subsidies is declining along with system costs, solar power still relies on subsidies. Thus, solar is viable only in countries with adequate incentives. As long as the industry depends on government subsidies and remains concentrated in a few key markets, large swings in demand because of policy shifts (which are inevitable linked to local politics) and supply levels (as panel producers overbuild in response to public policy expectations) will continue to cause substantial cash flow volatility for panel producers. Thus far in 2011, prices are in the

cut to the subsidy as well as an annual 400-MW installation cap. Spain's solar market dropped to just 69 MW in 2009. This drop in Spanish demand, along with growing supply and the 2008-2009 financial crisis, caused a supply glut and a crash in panel prices. In 2011, Spain announced a retroactive cut to FITs as the country's economic woes worsened, another essentially political decision that creates risks for future project financings.

Yet Spain is not alone. The Czech Republic also instituted an extremely generous FIT, which drove the installation of 1.2-GW photovoltaic (PV) capacity in 2010. Afterwards, the government retroactively revoked a five-year tax holiday for PV projects and has sought to cover more of its FIT burden through taxing carbon dioxide allowances and fees on public land use. A similarly large FIT led to a huge spike in installations in Italy in 2010. At one point, the government agency

End Market Demand Depends On Regional Factors

Europe is the mainstay

Europe is the largest end market, given the attractive FIT regime in many countries, and accounted for almost 80% of global demand in 2010. FIT policies are driven largely by a 20% renewable energy target for 2020. Every EU nation must increase its share of renewables by 5.5% from 2005 levels, with the balance on the basis of per-capita GDP. If solar energy constitutes even 10% to 20% of the renewable mix, cumulative demand in Europe through 2020 could, depending upon growth in electricity demand, total as much as 50 GW to 140 GW.

We expect both Germany and Italy to remain strong markets in the short-to-medium term. Germany contemplated installing caps after a record 7.4 GW of installations in 2010. However, the Fukushima nuclear accident in Japan and Germany's subsequent decision to shut down its entire nuclear fleet by 2022 have alleviated this concern because renewables will clearly need to play a larger part in the energy mix. With no new major markets emerging, we expect overall demand growth in Europe will be only about 10% in 2011, still very strong given the hypergrowth of 2010. If European fiscal

concerns worsen and cause the euro to weaken against the Chinese renminbi, it could create further headwinds for European demand in 2011 although falling PV prices would somewhat offset that.

North America is the next frontier

North America is shaping up to be the next big solar market. About 900 MW of PV capacity was installed in the U.S. in 2010, up 104% over 2009. However, given falling prices and the lack of growth expectations in Europe, we expect the U.S. to emerge as a relatively bigger part of the global market in 2011. The first quarter of 2011 showed 67% growth over 2010. Utility-scale PV projects grew to 28% of total U.S. installations in 2010 compared with 13% in 2009 and are likely to grow further, with about 6.5 GW of such projects currently under development.

Key policies supporting utility-scale and rooftop solar power in the U.S. include state-level renewable portfolio standards, a 30% investment tax credit through 2016 (including a cash grant option through 2011), and the Department of Energy loan guarantee program. Thus, U.S. demand is not vulnerable to annual FIT revisions although it remains susceptible to the delays of the loan guarantee program, the availability of project financing, and, in the longer term, to federal and state fiscal concerns.

In the long term, natural gas price trends are also important. Utilities that aren't subject to government mandated renewables portfolio standard (RPS) requirements see utility-scale solar projects as competition to natural gas peakers (plants that run only during peak times). The sharp fall in gas prices due to the abundance of shale gas has meant that wholesale price parity has been slower to occur despite the drop in panel prices. This dynamic could change because the U.S. market has, thus far, not been able to attract the supply of low-cost panels, primarily due to attractive FIT prices in Europe. This trend could change in 2011 given the much slower growth we expect in Europe and the continued oversupply in the panel market. The rooftop solar panel segment in the U.S. is somewhat more complicated, as not many states have instituted subsidies, nor have

local entities simplified the permitting process. However, we believe the ongoing fall in panel prices will allow the solar industry to reach grid parity in a fairly large number of states in 2011 to 2012.

China is stuck in neutral

Chinese panel manufacturers, which rely heavily on foreign markets, feared the global financial crisis would significantly lower demand. In response, the Chinese government instituted two temporary subsidy programs in 2009—The Rooftop subsidy (15 renminbi to 20 renminbi per watt) and Golden Sun. The latter would support about 600 MW of PV demonstration projects in the next two to three

years. The government would subsidize 50% to 70% of the total installation costs. These are both small, temporary programs.

The Chinese government has discussed, but not acted on, a national RPS and a national FIT. Some reports suggest that

Table 1 **Solar Panel Manufacturers Rated By Standard & Poor's**

	Rating
GCL-Poly Energy Holdings Ltd.	BB+/Stable
LDK Solar Co. Ltd.	B+/Positive
MEMC Electronic Materials Inc.	BB/Stable

Chart 1 **Solar Company Historical Average Selling Price**

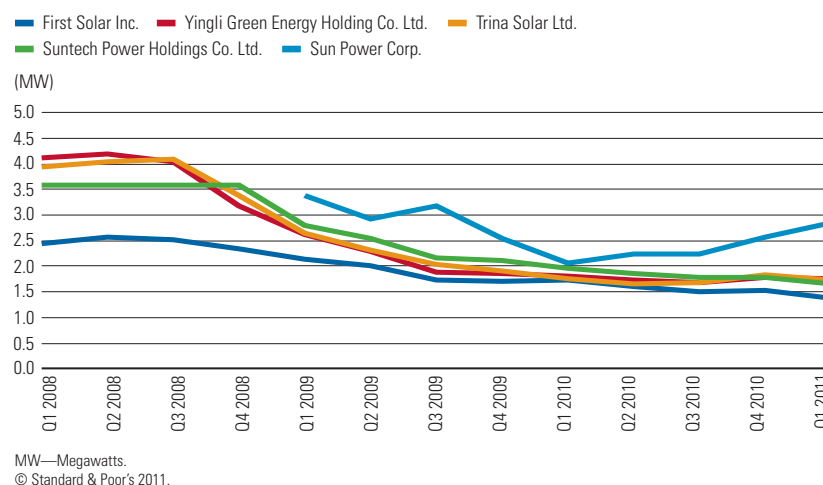
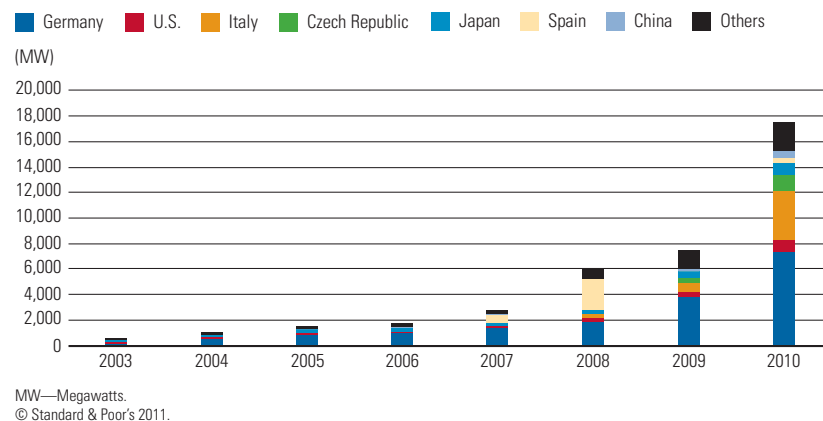


Chart 2 **Global PV Market Demand By Country**



China currently does not see the need for these to support its panel manufacturing industry in view of bullish global demand. Also, at the end of 2009, China set a goal of reducing the carbon intensity of its economy in 2020 by 40% to 45% from the 2005 level. China also promised to increase nonfossil fuels in energy use to 15% by 2020. Although the government might raise PV capacity in order to achieve these targets, we do not expect any near-term moves unless oversupply of panels and lack of demand growth abroad threatens output and employment levels at Chinese manufacturers.

Solar Panels Versus Semiconductors: Manufacturing And Cost Control...Not Moore's Law

Panel manufacturing, being a semiconductor-based industry, has given rise to comparisons with other semiconductor sec-

tors—including dynamic random access memory, liquid crystal display, and hard disk drive (HDD) manufacturers. However, we believe that the lessons, as well as the risks, of these industries do not apply to the solar panel manufacturing business although the HDD industry does come somewhat close (*see table 2*). A fundamental difference between solar panels and other semiconductor manufacturing is that solar panels aren't subject to rapid increases in performance and decreases in costs. Moore's Law, in which cost halves even as performance doubles every two years, applies to other types of semiconductors generally as a result of very large scale integration (VLSI) of transistors that place ever-increasing processing capacity on ever-smaller chips. Manufacturing of solar panels is more traditional, with cost control being key and economies of scale limited to the traditional spreading of fixed costs over larger units rather than due to VLSI.

Panel Manufacturers Are Integrating—Forward And Backward

With solar panels increasingly behaving like a commodity and manufacturers seen as price takers, companies are adopting strategies to ensure profitability. A key to cost control in recent years has been backward integration by C-Si panel producers into the manufacture of cells, wafers, ingots, and especially polysilicon since this last commodity was directly responsible for price spikes in 2007 and early 2008. While such backward integration into the manufacturing of components is readily understandable as providing greater cost control in a competitive commodity industry, what's perhaps unusual is the extent to which forward integration into power project development has become a central feature of many business strategies in the sector.

Table 2 Semiconductor Based Product Comparison

	Dynamic random access memory	Liquid crystal display	Hard disk drive	Solar panels
Market share	Concentrated	Concentrated	Concentrated	Fragmented. Nine companies with shares between 4% and 11%
Growth pattern	Highly cyclical	Cyclical	Cyclical	Rapid growth but susceptible to policy risks
Lifecycle stage	Mature	Late stage growth but already threatened by LEDs	Relatively mature and already threatened by solid state drives	Early stage growth; a small share of the energy market implies massive growth
End-market visibility	Used in short-lived assets with short development cycles; less visibility into quarterly consumer demand fluctuations	Used in short-lived assets with short development cycles; less visibility into quarterly consumer demand fluctuations	Used in short-lived assets with short development cycles; less visibility into quarterly consumer demand fluctuations	Used in long-life infrastructure assets with multi-year development cycles; better visibility; however, there is policy risk
Working capital	Customer is OEM and massive working capital swings are common	Customer is OEM and massive working capital swings are common	Customer is OEM and massive working capital swings are common	Non-bankable producers pose significant risk
Barriers to entry	High	High	High	Low
Commodity?	Yes	Yes	Yes	Yes but bankability currently important
Basis of competition	Features and price	Features and price	Features and price	Price and execution; less features driven; shows up in lower R&D costs as a percentage of revenue
Capital intensity	Very high; IP owned by suppliers	Very high; IP owned by suppliers	High; IP owned by suppliers	Medium to low, but capital expenditures to revenue is high due to growth; C-Si IP owned by suppliers
Economies of scale	Critical due to very high fixed and very low variable costs	Critical due to very high fixed and very low variable costs	Critical due to very high fixed and very low variable costs	Important but less critical due to much lower fixed costs and high variable costs
Cost roadmap	Moore's Law	Moore's Law although TVs, for instance, get larger but prices don't halve	Moore's law	Cost reductions due to improvements in throughput, efficiency, manufacturing cost control, and raw material (polysilicon) costs; no Moore's Law

OEM—Original equipment manufacturer. IP—Intellectual property. C-Si—Crystalline silicon.

Sometimes, this also includes developing a full-fledged in-house engineering, procurement, and construction (EPC) business.

Companies view the EPC business as an “enabler” in transitional markets, such as the U.S., that don’t have large FIT-based incentives. Given all the development risks and delays in the project finance market, this strategy reduces or eliminates some of these risks by providing a single entity that serves as project developer, panel supplier, EPC contractor, and project operator, with whom utilities or other power companies can negotiate. Completed projects are usually sold to other entities that are more natural owners of such assets—utilities, independent power providers, or financial investors.

The gross margin of the EPC business can often be lower but is likely to be more stable than that of panel manufacturing for the more competitive producers. The project development business can provide the following benefits:

- It enables companies to sidestep the volatility of the panel manufacturing business and have the economics of the power purchase agreement determine its overall margins. Companies thereby capture a greater share of the solar value chain and also insulate their margins from the volatility of panel prices, which is a market in substantial oversupply.
- Capturing utility contracts in an oversupplied market can be a way to check competitors’ ability to sell in one’s market, especially Chinese competition in the U.S.
- A project development pipeline also provides companies with flexibility to manage fluctuating global demand.

PV project construction is not only low risk, but also highly modular and, unlike construction of other types of central power generation stations, lacks a major critical path in construction—a specific sequence in construction that cannot be compressed in time just by adding labor. Thus, the pace of construction can easily be ramped up or down by simply adding more people to any project. This provides some flexibility in responding to falling or rising

demand in those markets where panel producers only sell panels by temporarily diverting panel production to or away from their own projects.

First Solar is perhaps the first and best known adherent to this strategy of forward integration. However, many other producers have since followed suit. SunPower also has an EPC business and acquired SunRay Renewable Energy, a European developer with a 1,200 MW development pipeline. MEMC Electronic Materials Inc., a large silicon wafer manufacturer, acquired Sun Edison, America’s largest developer of small rooftop projects. Sharp Corp., the large Japanese panel manufacturer, recently acquired Recurrent Energy Inc., a U.S. project developer with a 2 GW development pipeline in the U.S., Canada, and Europe.

ramp up capacity in what is increasingly becoming a commodity industry.

Some established, higher-cost manufacturers have survived thus far over lower cost Chinese and Taiwanese competition mainly because of “bankability” (see “Who Will Be Second Solar? Understanding Competition In Solar Panel Manufacturing” on page 30). But as more Chinese companies become bankable and as existing ones expand capacity, consolidation in the panel manufacturing industry and the exit of high-cost manufacturers increasingly appears inevitable unless there is an explosion in demand that allows all producers to thrive.

One factor significantly influences our view that even the largest and most profitable manufacturers—those considered

Companies view the EPC business as an “enabler” in transitional markets, such as the U.S., that don’t have large FIT-based incentives.

A Shakeout Is Likely Coming, But Panel Manufacturing Remains A Speculative-Grade Industry For Now

Competition in the solar panel manufacturing industry is intense. Price competition is fierce, and technology is rapidly evolving. The days of capacity shortages are over, and we expect the substantial overcapacity across the manufacturing process (including polysilicon, ingots, wafers, cells, and panels) to continue for the next several years. Companies can quickly and easily add production capacity since barriers to entry are low, both in terms of capital intensity and availability of off-the-shelf technology. Even if demand were to grow unexpectedly, the ease of adding new capacity implies that tight demand conditions will not last long. Another threat to industry margins is rapidly falling prices as numerous Chinese manufacturers

eminently bankable—are likely to remain speculative grade for the next few years. Fundamentally, the panel manufacturing industry is still immature since demand continues to depend on subsidies, a risky proposition given the uncertain political and fiscal environments in Europe and the U.S. Until solar power becomes viable as a stand-alone option without subsidies, manufacturers will be unlikely to achieve investment-grade ratings. **CW**

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Who Will Be Second Solar?

Understanding Competition In Solar Panel Manufacturing

Only a few companies stand out in the incredibly competitive and commoditizing solar panel manufacturing industry, which has several dozen large manufacturers and, reportedly, at least a thousand producers in all. Manufacturers must contend with falling photovoltaic (PV) panel prices, excess capacity, technology risk, and policy-driven demand uncertainty.

The clear leader is currently Tempe, Ariz.-based First Solar Inc., which has by far the lowest cost structure and highest margins in the industry (about 45% gross), and is currently the only large-scale producer of thin-film panels. First Solar also owns the largest pipeline of solar PV projects under development in the U.S. along with a successful in-house engineering, procurement, and construction division, a strategy that is

Overview

- Bankability, which reflects quality and indicates whether banks are willing to fund projects using panels from a specific manufacturer, remains critical to a manufacturer's competitiveness.
- Bankable producers themselves are expected to oversupply the market for the next few years.
- With more and more producers becoming bankable over time, the industry is commoditizing, and production cost structure becomes all-important.
- First Solar is the clear cost leader today, although Chinese competition is rapidly closing in.
- U.S. companies developing newer panel technologies remain promising but none has broken out from the crowd yet.

increasingly being adopted by other panel manufacturers.

As a number of companies try to replicate First Solar's success, the question now becomes, who will be "Second Solar"? Among the contenders are

higher-cost silicon panel manufacturers in Europe and Japan that benefit from strong brand names, such as Q-Cells SE or Sharp Corp., as well as other U.S. start-ups using newer technologies. The leading contenders, however, are

Chinese silicon panel manufacturers that have come to dominate the industry. These companies, including Suntech Power Holdings Co. Ltd., Yingli Green Energy Co. Ltd., and Trina Solar Ltd., benefit from government support and cheap power and labor, which could be the keys to reducing costs. The dynamics of price competition and market share that will help determine the winners in the solar panel industry are also important variables in our analysis of the credit quality of solar panel manufacturers. Moreover, the extent to which such competition drives panel prices down will inform the price stresses we apply to these companies when we analyze their financials.

Indeed, competition from Chinese manufacturers has helped push down prices and contributed to substantial excess capacity across the PV panel value chain, which we expect to last for at least the next few years. Solar panel prices have begun to fall again in 2011 after a period of relative stability in the second half of 2010, and currently are below \$1.50 per watt. Concerns about the quality of Chinese panels seem to have largely disappeared, at least for the larger companies. In order to survive, some higher-cost European and Japanese manufacturers have moved production to China and other low-cost Asian centers. However, some higher-cost producers continue to survive in what is rapidly becoming a commodity industry owing to their bankability—or the reputation for quality, performance, and execution that gives banks the confidence to lend to projects that use their panels.

Bankable Brands Are Key To Market Share

A comparison of the major panel producers' estimated production numbers with total market demand shows that these Tier 1 producers accounted for the vast majority of market demand in the past few years. Given the existence of dozens of Tier 2 and 3 producers and as many as a thousand smaller producers globally, we can surmise that many companies have an accumulation of

inventory. Clearly, demand is not being shared equally among all, and many producers, even those with lower costs than those in Tier 1, are being effectively shut out of the market. The reason is that they lack bankability, the critical feature that distinguishes manufacturers in what is otherwise a commodity market.

Most new entrants, especially those with newer technologies, and many smaller Chinese manufacturers with no track record of quality, are not considered bankable. Despite an excess of module capacity overall, the solar panel market was actually considered slightly undersupplied for a few months toward the end of 2010 due to a lack of bankable modules, so prices actually rose slightly. Bankability has somewhat insulated relatively higher-cost European, American, and Japanese manufacturers from the glut currently coming from China. However, as the global project finance market improves and lenders' risk appetite increases, and as more Chinese companies build sufficient track records, as leading Chinese producers already have—the number of bankable producers will increase.

We believe this market dynamic poses four kinds of risks for panel manufacturers, all of which could lead to lower prices or tighter margins.

- The large number of players in the industry results in greater competition and pricing pressures.
- The bankability of Chinese manufacturers other than Suntech, Yingli, and Trina Solar will improve over time, which will create additional price and margin tightness.
- The existing bankable producers are adding enough capacity to exceed total demand for the next few years, which could compress margins.
- Acquisitions of panel manufacturers by large, well-capitalized energy companies, such as French oil giant Total SA's recent acquisition of 60% of SunPower Corp., may give certain panel makers the financial resources needed to lower prices and gain market share.

We believe these trends could spell the demise of high-cost, stand-alone panel manufacturers unless there is an explosion in demand that allows all producers to thrive.

Bankable Modules By Themselves Could Oversupply The Market

Last year was a banner year for the PV industry, with global demand reaching 17.5 gigawatts, 141% higher than in 2009. Wafer, cell, and module prices, which had been in free-fall for much of 2009, stabilized across the value chain in the second half of 2010, and even increased slightly toward the end of the year due to higher-than-expected demand. Forecasts for demand for 2011 onward vary widely although most expect growth of less than 10% in 2011, given the reduction in German and Italian feed-in tariffs, and between 15% and 20% annual growth thereafter. However, even as demand growth moderates, low-cost, bankable producers continue to announce

large capacity expansions, which will further throw off the supply-demand balance in the sector (*see chart 1*).

While the most bankable and low-cost producers should be able to maintain adequate margins, others will undoubtedly suffer. We also believe the trends that have most distinguished the past few years—forward integration into project development, vertical integration, contract manufacturing, offshoring production to Asia, and the exit of some players from the market—is likely to accelerate. The extent of margin erosion and of consolidation will hinge on demand growth, which remains unpredictable, although the decline in prices can only help in this regard. The competitive dynamics in the industry will likely come down to four factors:

- Production costs,
- Bankability,
- Efficiency, and
- Performance (or kilowatt-hours per kilowatt yield).

First Solar currently has the best market position overall. Its leading cost structure, along with its currently small share of the market (about 8% in 2010), will allow the company to sell everything that it manufactures, so its market share will grow in line with the growth in its production capacity relative to market demand. The same is true of other Tier 1 producers, but First Solar stands out because of its low cost (*see table 2*).

Risk Aversion In The Utility Industry Favors The Market Leaders

The slow pace at which utility producers adopt new technology remains a significant risk for panel producers pursuing newer technologies. A key advantage for First Solar, and for currently established crystalline silicon (C-Si) players, is that, unlike the high-technology industry, the power and utility industry is highly risk averse and requires a long track record before accepting new technologies. And other than C-Si, First Solar's cadmium telluride, and some low efficiency amorphous silicon, no other technology is currently in large-scale production, much

Table 1 Solar Panel Product Production Plus Total Demand

In megawatts	2008	2009	2010
Suntech	495	704	1,558
First Solar	504	1,100	1,400
Yingli	296	525	1,061
Trina Solar	201	400	1,060
Sharp	384	408	1,022
Q-Cells	570	535	939
Canadian Solar	168	310	804
Hanwha SolarOne	0	0	798
Kyocera	225	275	650
SunPower	237	381	520
REC Solar	132	132	491
Sanyo	201	255	405
Schott Solar	205	310	390
SolarWorld	166	278	371
LDK Solar	0	0	356
Jiawei Solar China	0	0	337
Renesola	0	0	295
Top 17 total	3,784	5,613	12,457
Total demand	5,944	7,443	17,500

less demonstrating a stable, successful performance track record. This favors incumbents who have established the reliability of their technology.

Nevertheless, a number of companies are undertaking substantial research and development (R&D) efforts across a wide variety of technologies to improve panel efficiency and production processes. The technology that eventually will dominate could be quite different from C-Si technology, which currently dominates the market with a share of about 87% in 2010. But the length of time it takes for utilities to adopt new technologies may make it challenging for some startups to survive and prosper.

However, even if a newer technology establishes itself as the cost or efficiency leader, the sheer size of the energy market is another factor that somewhat mitigates the technology risk faced by incumbents: As long as any given technology can compete economically with fossil fuels and reach grid parity (the point at which renewable electricity is equal to or cheaper than grid power), the market can accommodate the simultaneous growth of different technologies, and the most profitable producer may be the one that employs the newer technologies.

Silicon Valley alone is reportedly home to more than 250 start-ups that are developing solar panels that offer lower dollar per megawatt-hour cost of power, either through higher efficiency or lower production costs. Many in the industry are touting copper indium gallium selenide (CIGS) as a technology that can trump First Solar's higher efficiency and lower costs. While a large number of CIGS startups are selling small quantities of these modules, none are manufacturing it on a large scale. Some critics are wondering if CIGS manufacturers can ever catch up given the emerging dominance of China. Other R&D efforts include the exploration of different semiconductor materials as well as "thin-film" silicon, which uses only about 25% of the materials that C-Si panel manufacturing currently uses. Also, various deposition techniques are also in use, including roll-to-roll printing of CIGS (similar to those used for inkjet printers) or flexible

substrates other than glass that can allow the integration of PV panels into building materials (called Building-Integrated PV or BIPV), which provide manufacturers with another way to distinguish themselves in a commodity industry.

Polysilicon Prices Are Central To The Competition Between First Solar And C-Si

First Solar's total manufacturing costs, at \$0.75 per watt in the first quarter of 2011, are still significantly lower than

Chart 1 Global Demand Versus Bankable Module Supply

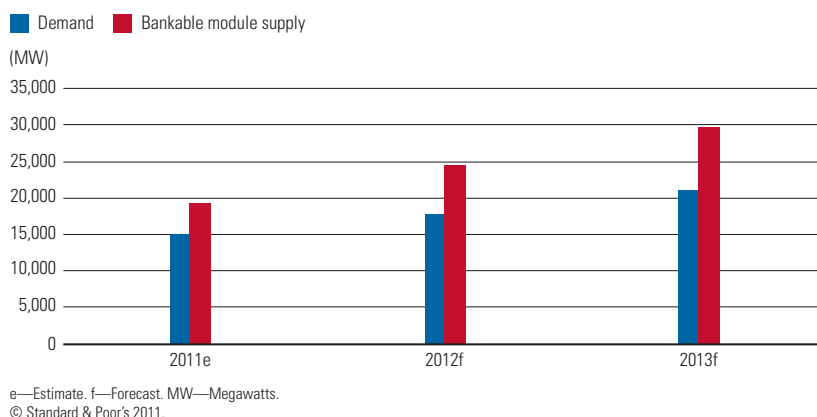


Table 2 Solar Panel Producer Key Players

	Strengths	Weaknesses
First Solar	Lowest costs by far EPC businesses Highly bankable	Competes with customers in U.S.* Cost improvement curve slowing Higher weight limits rooftop applications
Trina Solar ¶	Integrated Acquiring scale Low cost of capital Cost leadership in manufacturing Improving brand	No technology differentiation Reliance on low-cost Chinese capital
Yingli Green Energy ¶	Integrated Acquiring scale Low cost of capital Cost leadership in manufacturing Improving brand	No technology differentiation Reliance on low-cost Chinese capital
Suntech Power ¶	Scale Low cost of capital Best Chinese brand Strong research and development	Higher costs than Trina/Yingli No wafer capacity Reliance on low-cost Chinese capital
Sun Power Corp.	Highest efficiency Strong dealer network/rooftop market EPC business Integration and strong research and development Highly bankable	High cost structure
Sharp	Integrated Strong corporate parent Established Highly bankable Strong local presence in Japan	Capacity growth lags Chinese High cost structure relative to Chinese No technology differentiation

*As a project developer itself, First Solar effectively competes with its customers. This may be a weakness in the long run, but it is not at present. ¶Many Chinese companies are modeling themselves after the "Big 3" and seek to emerge as large, low-cost producers. Notable names include LDK Solar, Canadian Solar, Hanwha SolarOne, Jiawei Solar China, and Renesola. GCL Poly is rapidly emerging as a dominant global player in the production of polysilicon and wafers. EPC—Engineering, procurement, and construction.

those of the leading Chinese C-Si manufacturers even when accounting for First Solar's higher balance of plant costs. (First Solar's lower efficiency implies a larger number of panels for the same MW capacity, which necessitates more land, inverters, panel racks, wiring, and labor costs). The C-Si cost structure consists of two major components for analytical purposes—the cost of polysilicon, or poly (the raw material for the panels), and the non-poly manufacturing costs (the creation of ingots, wafers, cells, and panels).

First Solar's total manufacturing cost is currently equal to or less than the non-poly manufacturing costs of even the leading Chinese manufacturers. The cost of poly adds about \$0.35 to \$0.40 per watt today but was as much as 8x that amount not very long ago, demonstrating the risk that raw material price volatility poses to these Chinese manufacturers. Although massive expansion in

Chinese poly capacity is precisely what brought down poly prices, producing poly is a capital-intensive process in which capacity is added in an uneven fashion—and thus could be subject to typical boom-bust commodity cycles.

As a rule of thumb, every \$10 per kilogram change in the poly price affects the module price by about \$0.055 per watt (this ratio reflects current efficiency in the use of poly at 5.5 grams per watt and could decline as companies use poly more efficiently). Thus, even if poly prices were to fall significantly below the current spot price of about \$50 per kilogram, First Solar would still have a significant edge over the lowest-cost Chinese players. Over the next few years, the key factors determining who comes out on top will be whether First Solar's manufacturing costs dip further below the non-poly costs of the Chinese players, as well as the extent to which large new players,

such as GCL Poly Energy Holdings Ltd. (GCL), are able to lower poly prices.

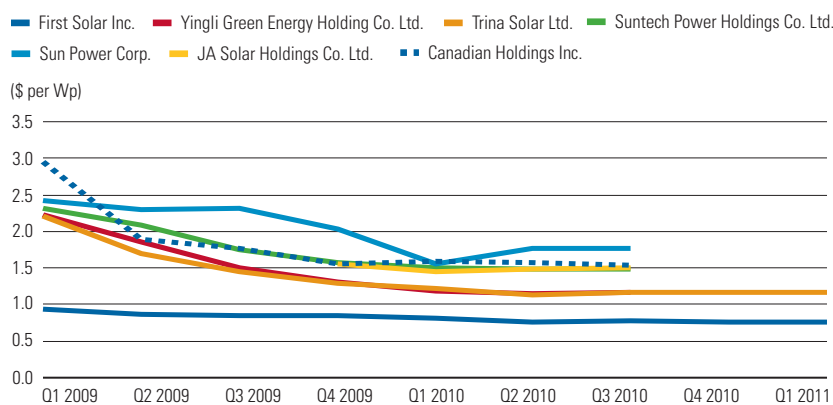
If Chinese companies can consistently source poly from companies such as GCL at \$25 per kilogram, or about \$0.14 per watt, the balance of plant disadvantage of First Solar panels (which many estimate at about \$0.15 per watt today) could make Chinese companies the lowest-cost producers, given that their non-poly costs are essentially equal to First Solar's total production costs. At any rate, no other non-Chinese manufacturer currently comes even close to replicating such a cost structure, and First Solar's plans to reduce costs to \$0.52 to \$0.63 per watt by 2014 positions them to best fend off Chinese competition in our view.

For those suppliers at the low-cost end of the supply curve, competition poses price and margin risks but no volume risks. They are unlikely to face inventory build-ups. The production cost of the marginal producer—the highest cost producer whose output is necessary to satisfy demand—will set the market price for panels. A stacking up of producers in ascending order of production cost is effectively the market's "supply curve," the intersection of which with total demand will determine the market price. In such a supply curve, the most bankable, low-cost players such as First Solar, Trina Solar, Yingli, and Suntech will satisfy demand first followed by medium-cost but eminently bankable producers like Sharp and SunPower. Tier 2 Chinese suppliers like Canadian Solar Inc., LDK Solar Co. Ltd., Jiawei Solar China Co. Ltd., and ReneSola Ltd. form a third group, based on low price and moderate bankability, followed by higher-cost C-Si firms such as Mitsubishi Corp., SolarWorld AG, Kyocera Corp., and REC Solar Inc.

It is possible that some of the lowest-cost producers may sell at prices below that of other producers (like First Solar did in 2007 and 2008), and for that reason they may be the first choice of power plant developers. Nevertheless, all companies whose cost is lower than that of the marginal plant will continue

For those suppliers at the low-cost end of the supply curve, competition poses price and margin risks but no volume risks.

Chart 2 Production Costs Of Leading Panel Manufacturers



Wp—Watt-peak.

Sources: Companies' SEC filings and Barclays Capital.

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to satisfy a share of the total market demand. Newer entrants or other thin film firms will likely be marginal or niche players. For instance, smaller manufacturers may develop competitive advantages in the commercial and industrial roofing markets by offering flexible panels or other unique features. United Solar, Ascent Solar Technologies Inc., SoloPower Inc., and Solyndra LLC are examples of manufacturers pursuing niche segments.

Who Will Be “Second Solar”?

Periods of tight supply-demand conditions are unlikely to last long because solar PV has such low barriers to entry in terms of capital expenditures, off-the-shelf equipment for C-Si panels is available, and capacity can come on line in relatively small chunks. Thus, we expect competition will become severe and oversupply will become the norm in the industry. We believe the exit of high-cost, stand-alone panel manufacturers will become inevitable in the next few years unless an explosion in demand allows all producers to thrive.

High polysilicon prices stifled competition from China in 2006 through 2008, but no longer. With poly prices hovering at around \$50 per kilogram, market prices for poly-based panels have rapidly declined to match those of First Solar. Although poly prices can be volatile, the Chinese have vastly expanded their production in recent years, which suggests that poly prices are unlikely to return to their 2007 highs.

In the aftermath of the global financial crisis, Chinese producers are using even more aggressive pricing tactics, at the expense of their margins, which we believe is an effort to preserve jobs while benefitting from the Chinese government’s stimulus spending and other forms of state support (such as subsidized financing, tax breaks, and special economic zones). As a result, there have been fewer failures of Chinese firms than we expected at the start of the crisis.

As with most semiconductor manufacturing industries, solar panel pro-

duction has seen what we believe is a long-term shift to Asia during the past several years, as companies search for lower costs. Even established European and U.S. vendors, such as Q-Cells, REC, First Solar, and SunPower are expanding their production facilities aggressively in Asia. Thus far, China has become the dominant producer of C-Si panels while Malaysia is a significant second, thanks to production for First Solar and Q-Cells. The Philippines also has a presence due to SunPower. First Solar also plans to build a facility in Vietnam with operations starting in 2012.

Despite the enormous solar-power subsidies in Europe, the region is no longer a major producer of panels. While this shift could become a political issue due to loss of domestic jobs to Asia, the cheaper solar power components made in Asia could arguably allow for feed-in tariffs to decline faster than they would otherwise while also benefitting the local installation industry (due to higher volumes of PV farm construction).

At this point, only First Solar has the cost structure to compete with Asia; at a cost of \$0.75 per watt, the company still beats the top Chinese players, which range between \$1.00 to \$1.20 per watt. Although CIGS manufacturers could also emerge as significant competitors in the longer term, it will take several years for these companies to establish their track records and be perceived as bankable. For all these reasons, we believe at this time that a Chinese company rather than a European or Japanese brand or a U.S. thin-film start-up will emerge as “Second Solar.” **CW**

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Mexico Has A Bright Future In Renewable Energy If It Can Clear Regulatory Hurdles

Earlier this month, Mexico announced a \$2.5 billion investment in new wind farms in the Baja California peninsula. It's the latest in a series of wind power projects that President Felipe Calderon has said will help the country meet its target of quadrupling its wind power capacity to 2,000 megawatts by the end of his administration's term next year. With oil reserves declining and an environment vulnerable to climate change, Mexico appears to be acknowledging its potential—and its need—for a strong renewable energy industry to support its economic growth over the coming decades.

Overview

- Mexico wants to increase its renewable energy capacity considerably to help meet its climate and economic goals.
- Its low labor costs and border with the U.S. are encouraging increasing cooperation between the two countries. This gives Mexico a strategic advantage when it comes to exporting clean energy.
- We believe, to reach its full potential, Mexico's renewable energy sector will need significant bank and capital market funding.
- Yet, in spite of Mexican authorities' progress in encouraging growth in this industry, numerous regulatory hurdles still stand in the way of project finance programs, in our view.

We also see a clear opportunity for the country to export clean energy, due to its border with the U.S. and its low labor and land costs. The U.S.-Mexico Bilateral Framework on Clean Energy and Climate Change is laying the foundations to make Mexico an attractive alternative site for renewable energy plants to export electricity to the U.S. grid. In particular, Mexico is well placed to export to neighboring California, which needs help in meeting its target of obtaining 33% of its energy needs from renewables by 2020.

Mexico's national development plan for 2007 to 2012 includes strategies for developing renewable energy programs, laws, and policy reforms. The country also has plans to reduce its greenhouse gas emissions by 50% by 2050 and increase its domestic renewable power

capacity to 7.6% of its energy matrix by 2012. However, industry observers have noted that 7.6% is just a drop in the ocean considering the country's long-term clean energy potential.

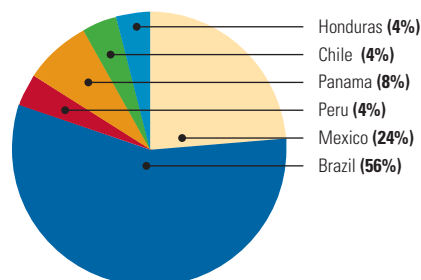
We believe that to meet its own demand and to exploit potential export opportunities, Mexico will need foreign investments that tap the bank and capital markets for funding. Yet, in our view, the country's regulatory framework for renewable energies is not sufficiently transparent and streamlined to attract the level of investments necessary for expanding this sector significantly. According to our criteria, the long-term credit strength of renewable energy projects depends on a predictable and transparent regulatory system that's sustainable over a long period (*for further details see "Updated Project Finance Summary Debt Rating Criteria," published Sept. 18, 2007, on RatingsDirect on the Global Credit Portal*). The Mexican administration is currently discussing policy mechanisms to further promote renewable energy. However, as an example, it's not yet clear to what degree it will concentrate on tariff regimes or tax incentives, or a combination of the two.

Mexico Is A Leader In Renewable Energy Project Financing In Latin America

Mexico's strategic position and policy has helped it become one of the most successful Latin American countries in attracting renewable energy project financing. In 2010, it captured one-quarter of the region's \$600 billion in investments in this sector (*see chart 1*). This makes it second only to Brazil's 56%, while Peru, Panama, Chile, and Honduras have also attracted large investments.

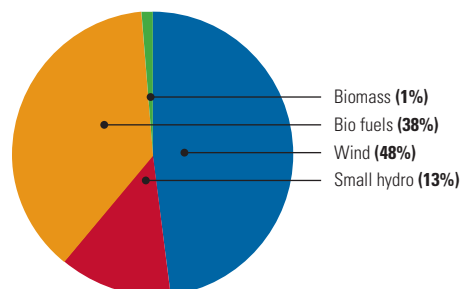
Wind power makes up the largest slice of renewable projects in Latin America. In 2010, 48% of the industry's regional financing was allocated to wind farms in Mexico, Brazil, and Honduras. Other significant investments consisted of the biofuel sector and small hydropower projects (*see chart 2*).

Chart 1 Latin American Renewable Energy Financing Distribution By Country 2010



Sources: Standard & Poor's, Infrastructure Journal.
© Standard & Poor's 2011.

Chart 2 Latin American Renewable Energy Financing Distribution By Energy 2010



Sources: Standard & Poor's, Infrastructure Journal.
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For Mexico specifically, the government agency ProMexico estimates foreign direct investments in wind, solar, and small hydroelectric projects will triple over the course of this year. Industry observers also see growing potential for geothermal technology, photovoltaic systems, solar water heating, and waste-to-energy.

New Policies Are Nurturing A Nascent Renewables Sector

Mexico has already implemented various renewable energy policy initiatives over the past decade. In 2004, the administration introduced a 100% tax rebate on machinery and equipment that prevents pollution and promotes renewable energy. In 2008, it created a fund for energy transition and sustainable use of renewable energy that allocates Mexican *pesos* (MXN) 3 billion (\$254 million) to projects per year during the present administration.

The government's Energy Sector Program set a goal to increase installed capacity generation from renewables—including large hydro of over 30 megawatts (MW) capacity—by 26% between 2007 and 2012. Two years later, the Special Climate Change Program for the period 2009 to 2012 set more specific goals to increase electricity generation from renewable energy to between 4.5% and 6.6% of the country's total (excluding large hydro) by 2012. The majority of this should come from wind power, according to industry observers, but also from small hydro, geothermal, biomass, and biogas.

To increase private participation, the government has also introduced new grid contract templates and a special low tariff to connect small and medium-scale renewable energy producers. It has further established public project bidding mechanisms for assigning projects.

To date, Mexico has completed 121 projects under the clean development mechanisms, generating 8.1 million tons of carbon dioxide equivalent (tCO₂e) in emission certificate reductions (CERs). The Ministry of Environment and Natural Resources reports that the state-owned *Comisión Federal De Electricidad* (CFE) (foreign currency BBB/Stable/—, local currency A/Stable/—; national scale mxAAA) is in the process of registering 30 projects

with the executive board of the Clean Development Mechanism, with a potential issuance of 15 million tCO₂e in CERs.

The government has also established several international agreements with multilateral agencies to fund renewable energy projects. These include the \$15 million Private Sector Wind Development joint project of the International Financial Corp. and Inter-American Development Bank (IADB), the \$50 million IADB Mexico Public-Private Sector Renewable Energy Program, and The World Bank Large-Scale Renewable Energy Development project.

To meet its own demand and to exploit potential export opportunities, Mexico will need foreign investments that tap the bank and capital markets for funding.

The Regulatory Framework Still Needs Strengthening

While the steps Mexico has taken so far represent great progress in the renewable energy sector, we see room to improve the framework for increasing credit visibility for project finance investments over a longer time span. Among the most pressing needs, in our view, are the following:

- Greater legal certainty over land tenure between projects and communal landholders. When building a facility, the promoters may choose to buy the land or pay rent for the life of the project. It can be difficult to relocate communal landholders because of legal uncertainties over their property rights and compensation.
- Priority access for renewable energy to the national distribution grid. Some European countries, by contrast, confer this on renewables producers to ensure the grid uses all the electricity they generate.
- Development of major grid interconnections along the border between Mexico and the U.S. This would facilitate a regional renewable energy

market, improve grid reliability, and stimulate electricity trade.

- An extension of national fund allocations for energy transition and sustainable use of renewable energy. These funds are currently only committed until next year's conclusion of the present administration.
- Transparency over the price that the state-owned utility CFE pays producers for purchasing electricity. Without price ceilings, it's difficult for promoters bidding for a project to estimate their future cash flows. What's more, we understand that

CFE doesn't disclose its selection criteria for choosing projects.

- Price concessions for clean electricity. CFE doesn't factor environmental externalities, such as the cost of pollution generated from fossil fuels, into the price it pays for electricity. This puts renewable energy at a disadvantage, in our view.
- A defined and clear tariff regime and incentive programs. Unlike most European countries, Mexico has not yet developed systems such as feed-in-tariffs or green certificate incentive programs. These schemes would add certainty for potential investment projects.
- Less bureaucracy in authorizing projects. The current permit process necessitates approvals from municipal, state, regional, and national entities, as well as regulators from both countries. Streamlining the entire process would, in our view, reduce the high embedded costs and improve profitability prospects.
- A liberalization of Mexico's electricity market to improve market dynamics. For now, the state-owned *Comisión Federal de Electricidad* has

a legal monopoly over generation, transmission, and distribution of energy in Mexico.

Mexican policymakers face a difficult task in deciding what policy mechanisms will most effectively reduce Mexico's greenhouse gases. Whatever agreement they reach will need to be economically sustainable and politically feasible, in our view. Nevertheless, we believe it's vital to iron out these difficulties so they can attract more project finance investments.

Capital Markets And Multilateral Agencies Are Funding Catalysts

Beyond more streamlined policies, we believe the clean energy sector in Latin America will require new capital market funding sources for renewables to be able to expand measurably in Mexico and across the rest of the continent. Most projects currently source funds elsewhere, such as from private equity, bank loans, and multilateral credit lines—and, above all, from sovereign incentives and investment programs. For the future, we predict that debt backed by revenues generated from the sale of carbon-offset credits could also provide investors with an alternative. This would reduce reliance on government subsidies to support renewable energy. However, these revenue sources involve other uncertainties related to delivery risk of certified emission reduction (CERs). Alongside risks typical for project finance, this includes risks related to complying with U.N. rules. What's more, with a post-Kyoto global treaty nowhere in sight, CERs generated after 2012 will likely be less valuable than pre-2012 CERs. In our view, this would make the market for CERs weaker than it was just a few years ago.

Given that renewable energy projects require long-term financing and large amounts of capital, we expect that the support of multilateral agencies and national development banks will continue to be instrumental. Besides offering economic support, they can also provide expertise and a level of confidence to attract the participation of private and institutional investors. In 2010, the Inter-American Development Bank (IADB),

The World Bank (via the International Finance Corp.), *Nacional Financiera* (Nafin), and *Banco do Nacional do Desenvolvimento* (BNDES) combined to account for about 40% of total monetary participation in Latin American project financings in renewable energies. These have included the EURUS 250 MW wind farm in Mexico, *Cerro la Hula* 102 MW wind farm in Honduras, and the *Pando Monte Lirio* 85 MW small hydro power plant in Panama.

Regulatory Hurdles Could Hold Back Progress

All this adds up to a lucrative future for developing renewable energy projects in Mexico over the coming years, in our view, if the country can continue to make its regulatory apparatus more investor-friendly. We predict that wind power and hydroelectric projects will be the most popular renewable energy sources in Mexico over the coming years because solar power requires larger amounts of capital to build facilities. Biomass also has the potential to become the third-largest provider in Mexico's renewable energy mix.

Today, syndicated bank loans and multilateral credit lines are financing the renewable energy sector. But the sector is growing quickly, so we believe it might be just a matter of time before renewable energy project financings tap the domestic capital markets for funding.

Nonetheless, any new reforms in the energy sector are unlikely in the near future since the current administration has just one year remaining in its term. If the regulatory framework is not clear and cannot provide investors with long-term legal certainty, we believe institutional investors could be skeptical of funding renewable energy projects. **CW**

Maria Tapia contributed to this report.

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Japanese Electric Utility Companies Stalled Energy Strategy Could Hurt Credit Quality

The ongoing Fukushima nuclear disaster following the March 11 earthquake and tsunami in Japan has pushed the country's energy policy to a crossroads. With public sentiment shifting away from nuclear energy, which had been at the forefront of Japan's energy plan for the next decade, and given problems with the alternatives, it is difficult to tell what direction a restructured national energy strategy will take. A sharp rise in fuel costs for thermal power and ongoing political uncertainty further complicate how best to provide this essential service.

Nevertheless, Standard & Poor's Ratings Services believes the key issue that remains for Japan (AA-/Negative/A-1+) is how to balance energy security, environmental protection, and support for the economy. Furthermore, because it has an enormous influence on the nation's strategy for economic growth, Japan's energy policy has the potential to affect the credit quality of companies in its electric utility sector and in other industries. In our view, the current uncertain energy policy is a downside risk for Japan's utility sector.

Overview

- Japan needs to rethink its energy policy, with the key issue being how to balance energy security, environmental protection, and support for the economy. Higher fuel costs for thermal power and ongoing political uncertainty complicate the task.
- Current uncertainty over Japan's energy policy is a downside risk for the credit quality of Japanese electric utility companies, in our view.
- Liquid natural gas is the most likely short-term substitute for lost nuclear power, renewable energy is the best longer-term solution, a partial restart of some reactors may be needed for a stable electricity supply, and we expect the nation's mindset will shift toward energy conservation to deal with power shortages.
- Prolonged energy shortages would force manufacturing into decline, dragging down economic activity and accelerating the hollowing out of industries from Japan. We will monitor whether the government crafts a well-balanced energy plan.

We believe the government has the following options:

- A shift to liquefied natural gas (LNG) in the short term to replace supply lost as a result of the nuclear disaster and prolonged safety testing of nuclear reactors;
- A strong push for wind and solar power this decade; and
- A partial restart of nuclear reactors now closed for regular inspections and safety tests.

Because each option has advantages and disadvantages, we expect the government will pursue all three to achieve its short- and long-term energy goals. Moreover, we also expect a shift in mindset toward energy conservation will continue across all sectors of Japanese industry and society to deal with power shortages.

In our view, the prolonged nature of the Fukushima disaster, the government's abrupt request in May that

Chubu Electric Power Co. Inc. (A+/Negative/A-1) shut down its Hamaoka nuclear power plant, and uncertainties about whether and how the government will help Tokyo Electric Power Co. Inc. (B+/Watch Neg/B) compensate those affected by the disaster all make it difficult for the government to achieve consensus on a new energy strategy. Thus, we think Japan's energy policy will remain unpredictable for some time. On July 11, the government announced plans to conduct safety tests of all existing nuclear plants to address concerns among communities situated near nuclear reactors. Details of the tests are uncertain, but they will be modeled after those conducted on European nuclear reactors. We think the new safety tests will extend the duration of shutdowns at reactors now closed for regular inspections. Furthermore, because the nation's

energy policy forms the backbone of the Japanese electric utility sector's creditworthiness, we believe prolonged uncertainty could hurt the sector's credit quality.

Because Japan is in short supply of natural resources and all of its islands are far from other countries, the government has pursued diverse sources of power generation. In 2008, coal accounted for 26.8% of Japan's total power generation, followed by LNG at 26.3%, nuclear at 24.0%, oil at 13.0%, and hydroelectric at 7.1% (*see table*). Wind and solar accounted for only 2.8% combined. The country has many potential geothermal energy sources, but developing them will take even more time and expense than developing wind or solar. In June 2010, the Japanese government prioritized nuclear power in its outline of a new energy plan for the next decade, with wind and solar power intended to support total power generation. However, in our view, the government needs to revise this strategy in light of growing public hostility toward nuclear energy.

Natural Gas Is The Most Probable Choice In The Short Term

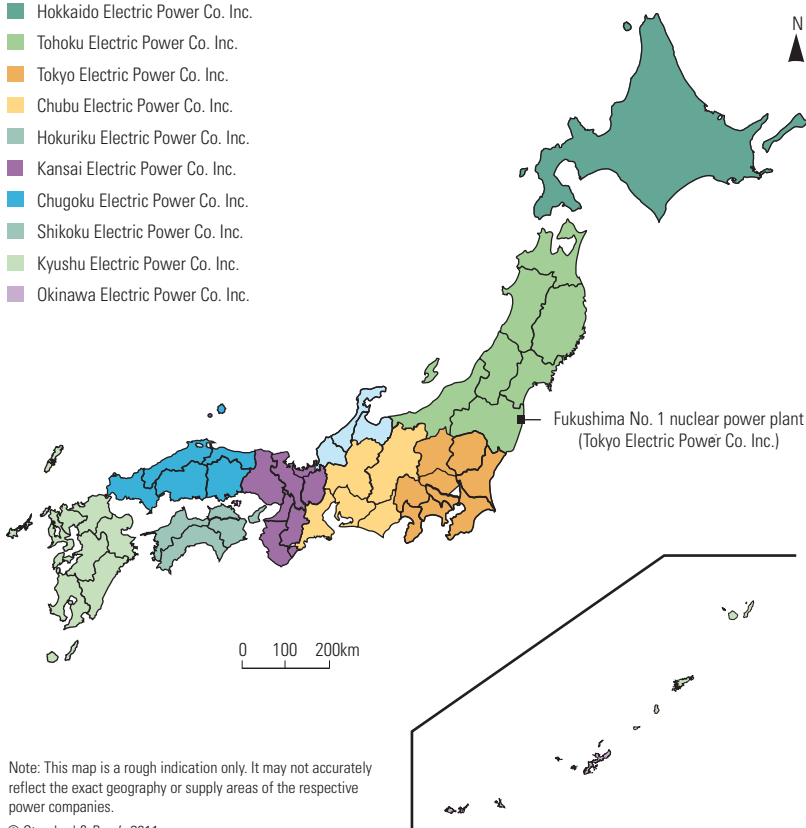
We think LNG is the most likely replacement for nuclear fuel that electric utilities will turn to in the short term because it produces lower carbon dioxide emissions and is cheaper than other alternatives. However, rising electricity tariffs seem unavoidable, and greater use of LNG means Japan will not meet its longer-term global commitments to reducing carbon emissions. In addition, given that other Asian countries are demanding greater amounts of energy while oil prices are rising, Japanese electric utility companies will face fierce competition as they increase LNG imports.

Renewable Energy Is The Most Desirable Option But Is Only Workable In The Long Term

As the antinuclear movement gains momentum among the public in Japan,

Supply Areas Of Japanese Electric Utility Companies

- Hokkaido Electric Power Co. Inc.
- Tohoku Electric Power Co. Inc.
- Tokyo Electric Power Co. Inc.
- Chubu Electric Power Co. Inc.
- Hokuriku Electric Power Co. Inc.
- Kansai Electric Power Co. Inc.
- Chugoku Electric Power Co. Inc.
- Shikoku Electric Power Co. Inc.
- Kyushu Electric Power Co. Inc.
- Okinawa Electric Power Co. Inc.



Note: This map is a rough indication only. It may not accurately reflect the exact geography or supply areas of the respective power companies.

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so too does interest in wind, solar, and geothermal power, which would not only improve Japan's energy self-sufficiency and lower its carbon emissions, but also improve public safety.

In our opinion, although it would be very difficult to replace all of Japan's nuclear power with renewable sources of energy in the short term, a shift toward renewable energy is the most pragmatic option for the nation in the longer term. However, Japan's wind and solar resources are not stable enough to make the switch to renewable energy an easy one, and significant hurdles—including the need for further technological breakthroughs and significant reductions in cost—dot the path toward such a goal. A dramatic shift in government policy toward renewable energy would be essential to the achievement of such a transition.

Specifically, Japan would need to address the following issues:

- Overcoming the technological challenges of transmission, distribution, and battery storage for wind farms and mega solar plants. Manufacturers and information technology companies must also further improve energy control systems to ensure the security of electricity supplies.
- Reducing costs. At present, according to data from the government's New Energy and Industrial Technology Development Organization (NEDO), wind costs around ¥15 per kilowatt-hour (kwh), solar costs around ¥40 per kwh, and LNG costs roughly ¥8 per kwh. NEDO estimates that it will take another decade to attain grid parity (the point at which the cost of renewable energy approaches that of thermal or nuclear energy).
- Providing incentives to promote use of renewables. Starting in April 2012, Japan plans to force the power sector to buy electricity from a wider range of renewable energy sources, through a revised feed-in tariff incentive scheme. Under such a scheme, utilities pass on extra costs to end-users. We consider this plan a key to the government's goal of making renew-

able sources of energy a pillar of the country's new energy portfolio. Given today's political uncertainty, however, the current session of parliament is not certain to approve the proposed feed-in tariff system, as it would add to the price of electricity at a time when tariffs already need to rise to reflect the cost of greater LNG use.

We expect the government will further promote renewable energy as a long-term solution, despite the many obstacles to its greater use. The key to fast-tracking the development of renewable energy, in our view, will be whether the government provides those industries pursuing it with full and continuous financial support.

We think LNG is the most likely replacement for nuclear fuel that electric utilities will turn to in the short term...

Entrepreneurs may also gain a foothold in renewable energy if the government accelerates deregulation of the country's power utilities. For example, Masayoshi Son, chief executive officer of Softbank Corp. (BB+/Watch Pos/—), has approached a number of prefectures with plans to build solar farms, but he would require access to transmission networks to do so.

Since 2007, the government has postponed discussions on fully deregulating the electric utility sector, instead signaling that it intends to reexamine the issue around 2013. However, discussions on expanding the use of renewable energy following the ongoing nuclear disaster could reopen this debate. Although we believe such discussions will take the government years to conclude and that the range of possible outcomes is still unclear, we intend to review the credit quality of rated companies in the energy sector as these talks proceed.

The Need For A Stable Electricity Supply May Require A Restart Of Some Nuclear Reactors

Given strong opposition to nuclear energy among local governments and the public, we anticipate there will be many twists and turns in political debate before electric utility companies can eventually restart now-dormant nuclear reactors. Amid the nuclear crisis, some European countries, such as Germany and Italy, have started to move away from nuclear power. Japan's need for a stable supply of electricity, however, may force it to restart its reactors. Obviously, the government, regulators, and electric utility companies will need to enforce more stringent safety standards and rebuild the nation's trust; the need to regain international trust is no less urgent. The government's safety tests comprise stress tests to determine how well nuclear reactors can withstand severe accidents caused by massive earthquakes, tsunamis, and other extreme events. Thirty-five of the nation's 54 nuclear reactors were under inspection as of June 30, and all of the remaining reactors are scheduled to undergo regular inspections within a year. If the companies that run these plants are not able to resume their operations this fiscal year,

we believe Japan's economy will further stagnate and electric utility companies' sales and operating profits will deteriorate significantly.

A Shift In The Nation's Thinking Toward Greater Energy Conservation Intensifies

Due to the currently narrow buffer between the supply and demand of energy in Japan, we expect a shift in the collective mindset toward conservation will accelerate—not only in industry but also in the household sector. Fortunately, Japanese companies that produce high-tech or capital goods, such as Panasonic Corp. (A+/Negative/A-1), Hitachi Ltd. (BBB+/Stable/A-2), Toshiba Corp. (BBB/Stable/A-2), Mitsubishi Heavy Industries Ltd. (BBB+/Stable/—), and Sharp Corp. (A-/Stable/A-2), are leaders in the development of advanced technologies for manufacturing energy-saving or low carbon-emission products and services. These companies, for example, develop energy-saving digital products, solar panels, high-efficiency integrated gasification combined-cycle (IGCC) coal-to-gas converters, and “smart grids.” In our opinion, accelerating development of these types of products and

services, in which Japanese companies already have a great advantage over their foreign competitors, will further promote a shift in thinking across the country toward energy efficiency and energy conservation.

Japan is Likely To Pursue All Options To Avoid An Economic Slump

Given the difficulties that Japan faces—and its need to address energy security, environmental protection, and economic support—we see little chance of a drastic change in energy policy at present. Moreover, we think it is likely that the government will compile an emergency action strategy that employs all available options. Although the Great East Japan Earthquake sent Japan's GDP into a tailspin in the first three months of this year, we expect the economy will recover as production picks up. Yet, despite this rebound, we expect GDP to contract between 0.5% and 1.0% for 2011.

In our view, extended energy shortages would force manufacturing to decline, which would in turn reduce consumer purchasing power and further drag down economic activity. In addition, raising electricity tariffs could accelerate the hollowing out of industries from Japan as manufacturers relocate factories overseas. There is no easy way to resolve Japan's current dilemma. We will monitor whether the government crafts a well-balanced energy plan to avoid such a scenario and to fulfill stable growth in demand for electricity—both now and in the future. **CW**

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Breakdown Of Generated Power By Country In 2008

Region (%)	Coal	Oil	Gas	Nuclear	Hydro	Others
Global	40.9	5.5	21.3	13.5	15.9	2.9
U.S.	49.1	1.3	21.0	19.3	5.9	3.4
China	78.9	0.7	1.2	2.0	16.7	0.5
Japan	26.8	13.0	26.3	24.0	7.1	2.8
Russia	18.9	1.6	47.6	15.7	15.9	0.3
India	68.6	4.1	9.9	1.8	13.8	1.9
Canada	17.2	1.5	6.2	14.4	58.7	2.0
Germany	46.1	1.5	13.9	23.5	3.3	11.8
France	4.8	1.0	3.8	77.1	11.2	2.1
Brazil	2.7	3.8	6.3	3.0	79.8	4.5
Korea	43.2	3.5	18.3	34.0	0.7	0.3
U.K.	32.9	1.6	45.9	13.6	1.3	4.7
Italy	15.5	10.0	55.1	13.3	6.1	0.0

Source: Electric Industrial Federation.



Utilities Will Feel The Squeeze As Europe Tightens Its Grip On CO2 Emissions In 2013

The third phase of the EU Emissions Trading System (EU ETS), which starts on Jan. 1, 2013, will impose significantly stricter environmental constraints on Europe's largest electric utilities than exist at present. Standard & Poor's Ratings Services believes this could lead to deteriorating credit quality in certain exposed segments of the sector, notably power generation. With the key elements of EU ETS Phase III now agreed in law, the scheme will impose a cap on EU greenhouse gas (GHG) emissions and expand its coverage to encompass new industries such as aviation and aluminum and ammonia producers. The scheme will also move toward a regime where companies will have to buy the majority of EU carbon emissions allowances (EUAs) at auction rather than get them for free. However, the transition to Phase III from Phase II—particularly the greater use of auctioned EUAs—is complex and could lead to the current carbon price of €13.5 per tonne of CO2 equivalent becoming more volatile toward the end of Phase II in December 2012—settling at around €19 per tonne, according to Deutsche Bank.

Overview

- The third phase of Europe's cap-and-trade scheme will have an adverse effect on utilities' credit-worthiness, especially those companies whose carbon liabilities form a greater share of EBITDA.
- Starting in 2013, power generators will no longer receive any free carbon allowances, and will have to purchase them at auction.
- Consumers will be left to pick up the tab for increased carbon costs, as generators pass through what we estimate could be an additional 7% to 20% per megawatt hour to wholesale power prices.
- Advance auctioning for Phase III allowances should start in 2012, in our view, to avoid supply constraints in the secondary market.

Revised Directive Ratchets Up The Pressure On Carbon Emitters

The European Commission (EC) is looking for Phase III of the EU ETS to deliver two-thirds of the EU's unilateral 20% emissions-reduction target by 2020, relative to 1990 levels. This equates to a 21% reduction by 2020 compared with the 2005 verified emissions baseline that the EU ETS originally established. It means that by 2020, Europe's cap-and-trade scheme could be saving around 500 million tonnes of CO₂ equivalent (MtCO₂e) per year, making it the biggest single policy

instrument for addressing climate change in the EU, and possibly worldwide.

From 2013, the revised EU ETS Directive (*see note 1*) sets out a centrally administered cap on GHG emissions, which reduces by 1.74% per year. The EC believes increased auctioning of EUAs (*see table 1*) will improve the economic efficiency of the EU ETS, as will limiting access to carbon offset project credits under the Kyoto Protocol from outside the EU to no more than 50% of the reductions the EU ETS requires. The latter should mean that more emissions

reductions will occur in the EU. In the interests of EU solidarity, 12% of auctioned EUAs will be redistributed to member states with lower GDP. We understand that these are mostly the Eastern European states.

Under the Phase III revisions, the EU, through member states, will allocate free allowances on the basis of product benchmarks to industrial sectors (aside from power generation; *see table 1*). The benchmarks will use the average of the top 10% most efficient GHG installations in the EU. Sectors at significant risk

Table 1 **How Carbon Allowance Allocations Will Change Under EU ETS Phase III**

Industry sector	—EU carbon allowances allocation—	
	Phase II	Phase III
Power generators (western Europe)	Company specific. Around 75% for free across the sector.	From 2013 no permits for free.
Power generators (eastern Europe)	Around 100% for free.	National governments can decide how many permits to allocate for free within the range of maximum 70% in 2013, falling to zero in 2020.
Aviation	Eighty-five percent of sector allocation for free. Individual company allocations determined by benchmark related to 2010 tCO ₂ /km.	Eighty-five percent of industry permits allocated for free. Individual company allocations determined by 2010 benchmark of tCO ₂ /tonne/km.
Industrial sectors not exposed to import competition.	Around 100% for free.	Eighty percent in 2013, falling to zero by 2025.
Industrial sectors exposed to import competition.	Around 100% for free.	Allocation defined by product-specific benchmark (defined as average of 10% most efficient sites) multiplied by historic output (2005 to 2008, or 2009 to 2010 if higher).

t/CO₂/km—Tonnes of carbon dioxide per kilometer.
Source: European Commission.

Table 2 **Potential Effect Of EU ETS Carbon Liabilities On The EBITDA Of Rated European Utilities***

Company	—Carbon cost per year (mil. €)—						—Liability as a % of EBITDA (incl. carbon cost pass-through of 80%)—		
	—Amount of CO ₂ per year (mil. tonnes)—			(At €13.5/tonne)	(At €25/tonne)	(At €30/tonne)	2009	2013f	2015f
Centrica PLC	2009	2013f	2015f	2009	2013f	2015f	2009	2013f	2015f
Centrica PLC	8.31	7.11	6.75	18.07	177.72	202.48	0.61	0.74	0.70
Drax Power Ltd.	19.85	21.62	21.77	165.29	540.62	653.19	65.21	63.7	64.40
E.ON AG	84.70	89.05	90.90	95.85	2,226.31	2,727.12	0.81	2.57	2.62
Electricite de France S.A.	66.54	70.15	70.55	61.24	1,753.70	2,116.56	0.42	1.87	1.88
Endesa S.A.	32.69	29.96	30.28	40.66	749.00	908.29	0.54	1.45	1.46
Iberdrola S.A.	27.01	27.18	26.24	85.39	679.40	787.11	1.32	1.46	1.41
RWE AG	149.10	175.31	181.92	592.65	4,382.69	5,457.54	5.90	7.05	7.33
Scottish & Southern Energy PLC	23.10	22.35	22.79	33.75	558.68	683.57	9.28	3.61	3.68
Vattenfall AB	89.70	88.31	89.70	373.95	2,207.76	2,691.13	7.83	5.26	5.35

*Based on aggregate EBITDA growth of 9.6% per year for all companies. Data are illustrative and do not necessarily represent Standard & Poor's view of future EBITDA or carbon liabilities for any of the companies listed. Carbon cost: €25 per tonne of CO₂ in 2013 (an estimate by Point Carbon, a carbon analytics and data provider); €30 per tonne CO₂ for 2015 (based on a PricewaterhouseCoopers survey consensus of €30.67 per tonne of CO₂ by the end of EU ETS Phase III). There are several reported prices for CO₂ emissions rights paid by a number of these nine companies in 2009, ranging from €13.00 to €16.05 per tonne of CO₂. RepuTex used a price of €13.5 per tonne of CO₂ for the 2009 emissions liability for companies when an explicit price was not available. As there are no free emission allocations for the power industry from 2013, to fully account for the CO₂ emissions cost component the projected EBITDA for 2011 to 2015 is calculated from the operating revenues less the operating cost without the emissions cost. Therefore, the cost of emissions is added back to 2010 EBITDA. f—Forecast.

Source: RepuTex.

of relocating production outside of the EU because of the carbon price (otherwise known as carbon leakage) will receive 100% of their benchmarked EUA allocation for free. Sectors not at significant risk of carbon leakage will receive 80% of their benchmarked allocation for free in 2013, declining to 30% in 2020 and zero in 2027.

Up to 300 million EUAs from the new entrants' reserve, which the EU ETS set up to accommodate new plants necessary to service economic expansion, will support the demonstration of carbon capture and storage (CCS) and innovative renewable technologies.

Subject to government consultation and approval by the EC, Phase III excludes small emitters. These are installations with CO₂ emissions of less than 25,000 tonnes per year and a rated thermal input (that is, the rate at which fuel can be burned at the maximum continuous rating of the appliance multiplied by the net calorific value of the fuel) of less than 35 megawatts. Also

excluded are installations using 97% or more biomass. However, plants that meet these criteria may use fossil fuels for start-up and shutdown.

Study Reveals Increased Carbon Exposure Liabilities For Utility Companies

We believe that EU ETS Phase III will have the greatest effect on the utility sector. We base this view on the results of a research study on our portfolio of utilities we rate that RepuTex, an independent carbon data and analytics firm, carried out on our behalf. Moreover, we think that the liabilities associated with carbon exposure under Phase III mean that the impact on credit quality will vary markedly between high and low emitters of CO₂.

A wide range of factors is likely to affect utilities' carbon liabilities, in our opinion. At the EU level, these cover:

- The carbon price;
- Worldwide developments related to the energy sector (the nuclear crisis in

Japan and social unrest in the Middle East and North Africa, for example);

- The availability of international carbon offset allowances (*see Appendix 1*); and
- Possible further revisions in the EU ETS (setting aside EUAs from the new entrant reserve, for instance). At the domestic level, factors include:
 - Local emissions reduction and energy efficiency regulations that supplement EU ETS targets, such as the U.K. government's electricity market reform. (*For more details, see Credit FAQ: "How Electricity Market Reform Could Affect The Ratings On U.K. Generators," on p. 56*);
 - The national marginal fuel at a particular time;
 - The availability of natural resources for renewable energy generators; and
 - National policy decisions on nuclear capacity.

At the company level, factors that will have an impact on carbon liabilities are likely to be:

Box 1 | Japan's Nuclear Crisis Could Be A Game-Changer For The European Utility Sector

The explosions at three of Japan's nuclear reactors in March 2011 following the earthquake and tsunami have sparked much debate about the use of nuclear power in Europe and an immediate response from the German government. Most EU ETS emissions forecasts over 2011-2020 assume that Germany's

nuclear fleet would have an average extended lifetime of 12 years (eight years for plants built before 1980, 14 years for those built after 1980). The events in Japan led the German government to impose a moratorium on lifetime extensions pending security checks at all of Germany's nuclear plants. Chancellor Angela Merkel followed this with the announcement that the seven oldest reactors (that is, those built before 1980) were to be taken offline immediately, pending further assessments. On March 24-25, the European Council announced that EU nuclear plants should undergo stress tests, and that the EC will review nuclear safety standards.

In 2010, nuclear power contributed 22% to Germany's overall energy mix (*see table*). According to Deutsche Bank estimates, shutting down the seven oldest reactors permanently with immediate effect and closing the remaining 10 reactors could potentially raise forecast EU carbon emissions allowance (EUA) demand over 2011-2020 by 370 million tonnes.

In both scenarios, natural gas from Russia (through the politically controversial Nord Stream pipeline in the Baltic Sea) is likely to replace most nuclear power production. This, says Deutsche Bank, would increase annual emissions by 40 million-50 million tonnes of CO₂. To put this in perspective, Germany's EUA allocation in 2009 was about 500 million tonnes, while Sweden's was about 22 million tonnes.

Breakdown Of Power Generation In Germany In 2010

Fuel source	Gross electricity output (TWh)	Share of total
Nuclear	137	22.0
Lignite	149	24.0
Hard coal	118	19.0
Gas	87	14.0
Oil	11	1.8
Renewables (excluding hydro)	81	13.0
Hydro	19	3.0
Total	621	—
Fossil fuel	365	58.8

TWh—Terawatt hours.
Source: Deutsche Bank.

- The company's current energy mix and the prevailing merit order of different fuels; and
- Short to medium term plans for decarbonizing its energy fleet.

The most expensive form of generation that is meeting demand at any point (the price-setting, or marginal, plant), either gas or coal, determines prevailing wholesale electricity prices. As the carbon price rises, we expect coal to increasingly become the price-setter, resulting in higher profit margins for generators using other fuels.

The removal of free allocations of EUAs from all electricity generators in Western Europe will in our view likely raise liabilities for all utility companies, and we incorporate this into our corporate credit assessment. In Eastern Europe, we understand there is still some uncertainty over the speed at which the EU ETS will introduce full auctioning, with confirmation only likely in the second half of 2011. The basic principle guiding the withdrawal of free EUAs from the power sector under EU ETS Phase III is that this is a regionally specific sector with little or no pricing competition from outside the EU.

In our view, electricity prices in Europe already largely reflect the carbon cost associated with utilities' energy mix. However, the rate of pass-through of carbon cost to customers varies from company to company. The RepuTex research study uses an aggregate figure of 80% for all three years under review—2009 (the first full year under EU ETS Phase II operation), 2013 (the first year of Phase III operation), and 2015.

Among our portfolio of rated utilities, the results of the RepuTex study indicate that carbon liabilities are likely to have the most significant effect on the EBITDA of Drax Power Ltd. (BB+/Stable/—), RWE AG (A-/Negative/A-2), and E.ON AG (A/Stable/A-1) (*see Table 2; more details on the RepuTex study methodology will be found in the sidebar on p. 50*). However, these calculations do not take into account future adjustments for the closure of nuclear capacities of utility companies in Germany in the wake of the Japanese nuclear crisis (*see Appendix 1*).

Consumers Will Likely Continue To Pick Up The Cost Of Carbon

We believe that power generators in liberalized energy markets that can set fully cost-

reflective tariffs are able to pass on a greater share of the cost of emission allowances to their customers through the wholesale electricity price. Power generators operating under regulated tariff regimes, by contrast, have to negotiate with the regulatory authorities to be able to pass on any additional cost arising from carbon emissions.

To date, there has been little effect on European utilities' credit quality arising from the cost of carbon liabilities because the majority of companies are able to largely pass through these liabilities to electricity consumers via the wholesale power price. In addition, lower CO₂ emitters such as utilities that generate power from nuclear, hydro, and renewable sources have benefited from rising power prices because they receive increased power price revenues without having to meet any emission liabilities.

For example, in the U.K., according to a study by IPA Energy Consulting (*see note 2*), the approximate profit the utility sector gained as a result of the combination of free EUAs with a large share of pass-through of marginal costs was £800 million per year between 2005 and 2007 (based on the annual allocation of 130 MtCO₂e).

Box 2 | Power Sector Emissions Are On The Rise In Europe After A Recessionary Stall

In Europe, emissions from power generation have fallen gradually since 1990 as power stations have been upgraded and the industry invests in carbon abatement technologies. The absolute level of emissions declined significantly in 2008-2009 due to lower demand brought on by the global recession. In 2009, verified absolute CO₂-equivalent emissions from generation installations were 1,315 million tonnes, which accounts for 42% of the total emissions regulated under the EU ETS.

In 2010, European emissions rose 2.6% (29.5 million tonnes) compared with 2009. Most of this increase is due to Germany's electricity generation emissions, which were up by 5.2% (18 million tonnes). German power suppliers therefore face the biggest shortfall from 2013 in EU carbon emission allowances (EUAs): Their emissions climbed at the higher end of analysts' forecasts, almost doubling their combined shortfall to 91.4 million tonnes of CO₂ equivalent (MtCO₂e). The U.K. power sector had the second biggest shortfall, at 35

MtCO₂e, resulting from a rise in emissions of 3.5%. Together, the U.K. and German power sectors accounted for almost the entire aggregate shortfall in the power sector in Phase II. Eight other countries including Poland, Finland, and Italy also saw increases in fossil fuel-fired generation and posted a shortfall of EUAs in the power sector, but their volumes were much smaller.



By contrast, Spanish generation emissions were down by 18% (16 million tonnes). This was largely down to higher levels of renewable energy (both hydro and wind power recorded a five-year record output), and hence lower fossil fuel-fired generation, leaving utilities with a surplus of 2.7 million EUAs. We think this represents a big shift, as Spanish utilities were short of EUAs in 2009.

Romanian electricity emissions fell 20.3% to create a surplus of 15.8 million EUAs for utilities—the largest among Europe's power sectors. Spain and Romania are two of the 10 countries with the biggest national allocation plans in Europe.

Fiscal, regulatory, and market developments are likely to influence electricity retail prices in Europe to a greater extent than the EU ETS, in our view. However, we calculate that the price of carbon passed through to consumers could add between 6.6% and 20.0% per megawatt hour (MWh) to wholesale power prices based on the German wholesale price for 2012 delivery of €52.64 MWh at the end of June.

Carbon Prices Face An Uncertain Future

The carbon price is one of the main factors influencing investment decisions in the utility sector at present. The price of carbon in turn depends on both carbon market fundamentals and how these fundamentals play out under particular economic, political, and environmental circumstances.

Emissions forecasts up to 2012 have fallen over the past two years because the global recession and falling gas prices have cut overall emissions within the EU (*see Appendix 2*). Yet the EC has not adjusted the number of allowances within the EU ETS, the market regulator. Consequently, many believe the scheme has an oversupply of allowances through to 2013 (*see chart*).

We see two factors influencing the carbon price. First, the demand from the power sector for cheap allowances (that is, carbon offsets, which are cheaper to buy than EUAs). Second, the ability of the market to efficiently transfer surplus EUAs from Phase II of the EU ETS to meet the anticipated shortage in the utility and aviation sectors in Phase III.

Timing EUA auctions in line with forward electricity sales is crucial to the carbon price for the remainder of Phase II, in our view. If fewer allowances are auctioned than are required to match forward electricity sales, then generators will look to the wider market to supply them with EUAs. This effectively pulls forward demand for Phase III allowances into Phase II. With power generators starting to sell forward into Phase III from as early as mid 2011, we believe the earlier in 2012 that auctioning starts the lower the risk will be of supply constraints in the secondary market.

In particular, a surprisingly cold or warm spell of weather, or perhaps an extended

period of still or low wind, would trigger fossil-fuel power generators to purchase higher volumes of EUAs for a short period of time to cover additional generation emissions. If this occurs before the early auctioning of allowances for long-term contracted generation into Phase III, we believe EUA prices may spike. The ability of companies to bank unused allowances into future years does not help this situation because it discourages them from selling them today, artificially reducing the EUA allocation available to the market.

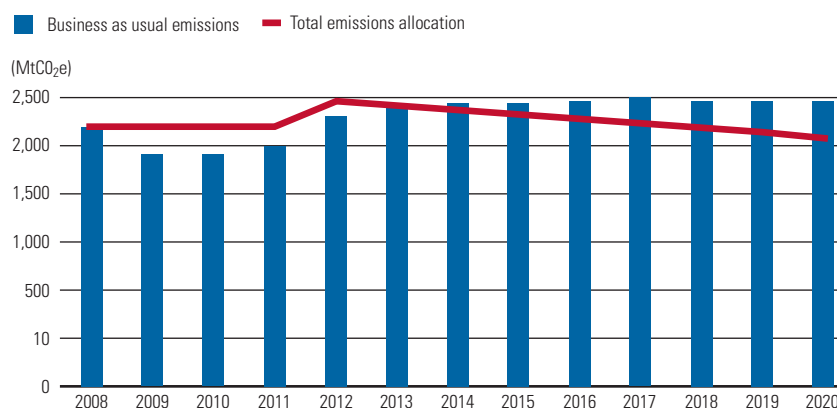
In addition, according to industry experts, there is potentially material upside risk to both EU emissions forecasts and the EUA price forecasts the RepuTex study used, depending on how

events unfold in Germany with regard to its nuclear generating capacity.

However, the EU ETS is a politically sensitive market and is unlikely to be left to its own devices, in our opinion. We believe that there is a limit to which the carbon market will set a potential carbon price. Beyond this, we think regulators would intervene to prevent excessive power price spikes. This is especially relevant during a period of economic constraint because affordability of power would likely be a greater priority than the level of emissions.

The economics of generating plant new-build and closure decisions are highly sensitive to the long-term projections of carbon price, in our opinion. In Europe, the introduction of a cap-and-trade scheme

Annual Imported Crude Oil Price



EU ETS—European emissions trading scheme. MtCO2e—Million tonnes of CO2 equivalent.
Sources: Bloomberg New Energy Finance, EU Commission, Citi Investment Research and Analysis.
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Table 3 **Rated European Utility Companies Covered By RepuTex Carbon Liabilities Study**

Company	Country of domicile	Corporate credit rating*
Centrica PLC	U.K.	A-/Stable/A-2
Drax Power Ltd.	U.K.	BB+/Stable/—
E.ON AG	Germany	A/Stable/A-1
Electricite de France S.A.	France	A+/Stable/A-1
Endesa S.A.	Spain	BBB+/Stable/A-2
Iberdrola S.A.	Spain	A-/Negative/A-2
RWE AG	Germany	A-/Negative/A-2
Scottish and Southern Energy PLC	U.K.	A-/Stable/A-2
Vattenfall AB	Sweden	A/Negative/A-1

*As of July 1, 2011.

Appendix 1: International Carbon Offset Allowances Availability

The EC allows regulated companies to use international carbon offset credits toward their emissions liabilities. Developing countries earn these credits under the auspices of the U.N. as part of the Kyoto Protocol. Projects at power stations and industrial facilities that reduce CO₂ or other greenhouse gas (GHG) emissions, as well as renewable energy projects that displace the use of fossil fuels, are awarded 1 CER (certified emission reduction) or ERU (emission reduction unit) per tonne of CO₂-equivalent reduced or avoided.

Offset credits trade on a global market and national governments can purchase them toward their Kyoto Protocol compliance. Companies that are allowed to use them toward domestic regulatory systems such as the EU Emissions Trading Scheme (EU ETS) can also buy them. Because reducing emissions in developing countries produces them, the cost per tonne tends to be lower than the cost of an EUA (EU carbon emissions allowance). Companies can therefore reduce their emissions liability by using their full quota of carbon offsets each year.

Since the legal framework of the Kyoto Protocol establishes offset credits, there is significant uncertainty about their future availability

once the protocol expires in 2012. The EC intends to allow carbon offsets (up to a limit of 1.8 billion) into Phase III of the EU ETS. In the event of the Kyoto Protocol not being extended beyond 2012, and the protocol's Clean Development Mechanism not continuing under an alternative framework, the EC is likely to make bilateral agreements with offset project host nations to enable the generation of offsets for the benefit of EU-regulated companies.

The EC limits the use of carbon offsets to ensure that some level of emissions reduction actually takes place domestically rather than just overseas. The total number of offsets the EC allows into the EU ETS is 1.8 billion tonnes per year between 2008 and 2020. However, the source of some of the offsets has become controversial and the EC has proposed restricting those offsets that will be eligible for admission to the EU scheme in the future. On Jan. 21, 2011, the European Council agreed to a restriction of offsets from trifluoromethane (HFC23)-reduction projects and nitrous oxide (N₂O) from adipic acid projects from the end of April 2013. Market participants estimate that this will have the effect of removing around one-half of the current supply of carbon offsets from the market in future years.

Appendix 2: Methodology For Assessing The Effect Of Carbon Liabilities On EBITDA

RepuTex, an independent carbon data and analytics firm, conducted an illustrative study on our behalf to help assess the effect of carbon liabilities on the EBITDA of a sample of our rated European electric utility companies (see table 3).

Emissions projections:

Emissions projections cover only the generation business of each company. The projection incorporates the following factors:

- The market share for the generating activities of these companies is based on their historical generation patterns, scheduled retirement and addition of fossil-fuel plants, and new renewable energy generation projects.

- RepuTex calculated projected generation of the nine companies based on market share and projected electricity demand in the countries of operation from 2011 to 2015.
- It calculated emissions factors using companies' historical emissions, trends, and retirement and addition (renewable) of generation assets.
- It added emissions of new fossil-fuel plants to the above emissions projections. If there was no specific date given for a new entry in a year, then RepuTex allocated one-half of the full-year emissions to the first year of operation.

has led to a reluctance to build new fossil-fuel power stations, particularly coal-fired power plants. Large utilities such as RWE, E.ON, and Enel SpA (A-/Negative/A-2) can still afford to build coal-fired power plants occasionally, to maintain diversification in their portfolio and as a back-up for renewables. However, we believe that coal-fired power generation as an independent power producer will become increasingly uneconomic in Europe with the onset of EU ETS Phase III. **CW**

Notes

- (1) More information on the EU ETS can be found at <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CONSLEG:2003L0087:20090625:EN:PDF>
- (2) From a report titled "Implications of the EU Emissions Trading Scheme for the Power Generation Sector." For more details, contact <http://www.ipaenergy.co.uk/>

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Why Regulatory Risk Hinders Renewable Energy Projects In Europe

Ambitious targets for clean energy generation in the EU have put renewable energy at the forefront of discussions about how to meet Europe's future energy needs. And political reactions to the recent nuclear crisis in Japan—which prompted Germany, for example, to shift its energy policy toward renewables and away from nuclear—are also fueling the interest in renewable energy.



But despite the momentum behind renewables, Standard & Poor's Ratings Services sees signs that regulatory risk is becoming a bigger issue for these projects. One example is the recent decision by the Spanish and Czech governments to adjust their regulatory support frameworks, including subsidies, for existing renewables projects, in part retroactively. Because we consider regulation to be a key rating factor in our assessment of renewable energy projects, alongside technical factors such as efficiency and fuel sources (sun, wind, or hydro), we've been watching these developments closely.

In this FAQ, we answer investors' frequently asked questions about our assessment of regulatory risk in renewable energy projects and identify potential areas of credit concern.

Q. *What is Standard & Poor's approach to analyzing renewable energy projects?*

A. As for any other single-asset nonrenewable financing, we analyze renewable energy projects using our project finance criteria, which we supplement with a review of the key credit factors specific to the renewable technology in question.

In essence, we evaluate projects case by case, taking into account the predictability of a project's cash flow and comparing this cash flow to the project's debt repayment profile.

Q. *Why has regulatory risk become more significant for European renewable energy projects?*

A. In our opinion, budgetary constraints in the public sector and the need to implement severe austerity measures in some countries are calling into question the sustainability of financial support for renewable-energy development in Europe.

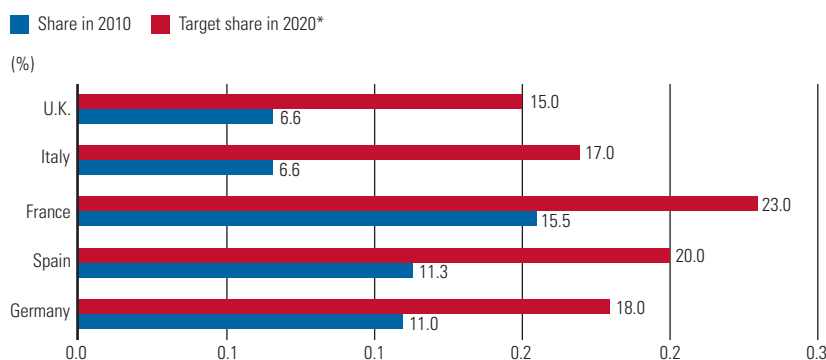
Regulated incentives for renewable energy projects often underpin their financial viability: For instance, subsidies to solar power projects in Europe can account for up to 85% of their initial revenues. This, in our view, illustrates the importance of predictable, ongoing financial support for renewable energy projects, and highlights the credit risk associated with any changes to this support.

Q. *How does Standard & Poor's determine whether the regulatory system is likely to support a project's credit quality?*

A. We aim to determine the contractual and regulatory arrangements under which the renewable energy project will operate, and assess their supportiveness both at the outset of the project and over its lifetime.

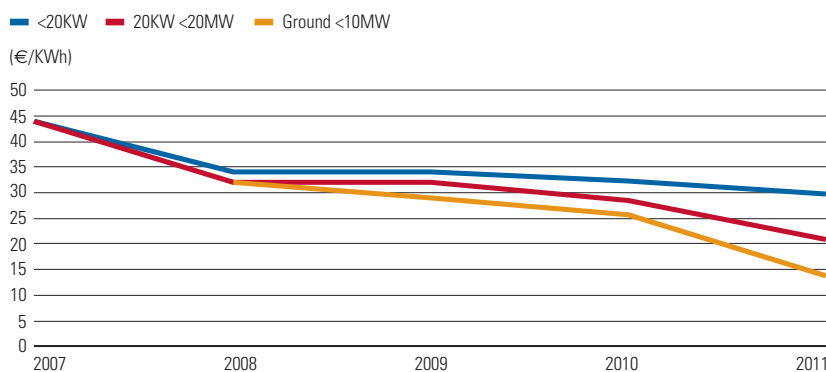
In analyzing the regulatory framework for a given asset, we start by evaluating the form of support commitment. Regulatory support to any given project in any given country normally can be in the form of either a decree or law approved by the government or parliament, or a power purchase agreement or other offtake agreement with a utility managed by a specific industry sector regulator, or administered through a contract between an offtaker or clearing entity (that is, the contracted purchaser of the electricity, possibly state-owned) and the power generator. We then

Chart 1 Share Of Electricity Consumption From Renewable Energy Sources Within Selected European Countries Versus EU 2020 Target



*As defined under EU Directive 2009/28/EC.
© Standard & Poor's 2011.

Chart 2 Evolution Of Spanish Feed-In Tariffs 2007–2011



KWh—Kilowatt hour. MW—Megawatt.
Sources: Standard & Poor's and MICyT.
© Standard & Poor's 2011.

analyze the credit quality of the counterparty of such support, which may impose a cap on the project rating.

Given the importance of regulatory incentives to a renewable energy project's total revenues, we look for this support—which may be constant or decline over time—to ensure that the project's cash flows meet the established debt service repayment profile over the life of the project.

Q. *How sustainable is the financial support for renewable energy in EU countries, in Standard & Poor's opinion?*

A. EU member states have committed to ambitious targets for the replacement of fossil fuels with renewable energy under EU Directive 2009/28/EC. Although feed-in tariffs (FITs) have proved effective in boosting investors' appetite for renewable energy assets in the past few years, there is still some way to go to meet the 2020 targets for electricity generation from renewable energy sources (*see chart 1*). We believe governments might therefore continue to provide a high level of financial support to plug the gap until they are reassured about reaching the targets.

However, we believe this generous support—which creates direct costs for both governments and consumers—could ultimately prove unsustainable, especially in light of the current subdued economic growth and strict public and private sector budgetary constraints.

In our view, a sustainable regulatory system is one that balances the promotion of renewable energy against the costs to the government and consumers. In evaluating this balance for individual projects, we focus on the following factors for each particular regulatory regime:

- *The size of the financial support and incentives.* This is illustrated by the gap between the tariff paid to energy producers and the market price end users pay (*see table 1*). We view FITs and other incentives that are considerably above market cost to be at the

greatest risk of cutbacks, especially in times of economic stress and budgetary controls. Furthermore, the gradual decline in production costs as a technology matures may exacerbate the political pressure to reduce visible incentives such as FITs. Although the rate of return of a project is not a key factor in our analysis of creditworthiness, we've observed that very high expected returns (exceeding 20% to 25%), which have been common for renewable energy projects in the past few years, may also indicate a high risk of regulatory changes. When the electorate perceives that the returns for well-established and low-risk projects and technologies are high, it can erode the political support for regulatory frameworks allowing such returns. We witnessed such an effect in the Czech Republic.

- *Affordability.* We compare the direct cost to the government of the FITs and tax incentives with the government's current and expected budgetary and debt positions in relation to its budgetary and debt targets. Those countries in which this support represents a higher proportion of GDP are the most at risk of regulatory changes, in our view, especially if they are under budgetary pressure. We believe that a government's incentive to reduce subsidies on future projects (or even those that are already operational) will increase in line with its budgetary constraints and will be higher if the potential cuts yield significant savings (we discuss this further in the final question below). Continued subsidies in those countries where there is already a deficit of funding for energy tariffs, such as Spain, are also more at risk, in our opinion.

- *Control mechanisms.* We view a cap on installed capacity as credit positive in any regulatory regime, insofar as it may prevent unsustainable growth of subsidies. The absence of caps in the regulatory framework allow for uncontrolled growth, which then translates into subsidy payments that may be too high for the economy to uphold. This was a

significant factor behind the recent revisions by Spain and the Czech Republic of their solar photovoltaic (PV) regulatory frameworks.

- *The effectiveness of the grid management.* Ineffective management of the electricity grid may increase the cost of back-up energy supplies considerably, in our view.

Q. *Are FITs the only incentive Standard & Poor's considers when assessing regulation and regulatory risk?*

A. No. When evaluating the credit quality of a renewable energy project, we look at all incentives the regulatory framework provides to the project from the outset. FITs are just one aspect of

the support regime in Europe, albeit a more visible and potentially controversial one, because they are paid directly to the generator. Other features of European regulatory frameworks, the revision of which may affect the economic viability of a project, include:

- Providing priority access to the market and/or distribution grid for electricity produced from a renewable source;
- Providing green certificates to generators for the electricity they produce from renewable sources. These certificates can be traded, usually to firms that do not have sufficient renewables in their energy mix; and
- Favorable tax treatment for the initial project investment, or for profits linked to renewable energy production.

Q. *When analyzing renewable energy projects, does Standard & Poor's assume that regulatory support will remain constant?*

A. No. We would anticipate that the support for a given transaction, as defined at the outset, would be honored and remain stable over the life of that transaction. However, the regulatory regime within a country will evolve over time: In our experience, transparent regulations will explicitly mention a fixed level of subsidies to projects over a certain period or until, say, a target level of installed capacity is reached. At that point, a new regulation (in the form of a decree or law) replaces the old one and new, possibly lower, subsidies will apply to any new projects.

Over the past few months, for instance, regulatory revisions across Europe have led to reductions in the solar PV tariff ranging from 15% in Germany to 70% in the U.K. In Spain, subsidies to solar PV projects have fallen over the past four years as the government revised its FIT framework (see chart 2).

In our view, the regulatory support for renewable energy will continue to erode in all main EU markets as the technology matures and the price per unit of power generated drops. We believe it's likely that there will be a point at which support is no longer necessary, specifically when the unsupported cost of electricity

Table 1 **Comparison Of Consumer Electricity Prices And Tariff Rates Paid to Generators In Europe In 2011**

Average electricity rates in 2011 (€/KWh)	Germany	Spain	France	Italy	Czech Republic
Houshold electricity rate	25	19	13	21	16
Industrial electricity rate (at a consumption level of 2,000 MWh/year)	12	12	7	13	12
Industrial electricity rate (at a consumption level of 24,000 MWh/year)	9	9	6	11	10
Tariffs paid to generators (€/KWh)					
Wind (onshore)	5-9	7	8	30	11
Wind (offshore)	13-15	7	31-58	30	11
Solar PV	32-43	14-30	27-58	36-44	23
Solar thermal	—	28	—	—	—

KWh—Kilowatt hour. MWh—Megawatt hour. Solar PV—Solar photovoltaic.
Source: Europe's Energy Portal.

Table 2 **Breakdown Of Feed-In Tariff Subsidies Paid To Renewable Energy Projects In Spain In 2010**

(Mil. €)	Wind	Solar PV	Solar thermal
Jan.	183	140	3
Feb.	196	103	2
March	207	119	2
April	206	135	2
May	213	209	10
June	134	247	6
July	172	289	17
Aug.	117	276	21
Sept.	124	318	30
Oct.	133	293	29
Nov.	118	261	29
Dec.	187	222	23
Total	1,990	2,612	174
Share of total*	28%	37%	2%

*The remaining 33% share of FITs, which takes the total subsidy for the year to €7 billion, is for other renewables such as hydro and biomass. Solar PV—Solar photovoltaic.
Source: Comisión Nacional de Energía.

generation from a given renewable source matches that from fossil fuels. However, we think this so-called “grid parity” price point is probably five or more years away, and will depend on the level of support in a given jurisdiction, the availability of the natural resource (wind or sun, for example), and the amount and speed of technological progress. That said, the implementation of carbon taxes and costs on the carbon-generating industries should hasten this grid parity.

In the near term, we believe the policy choices of individual governments—many of which face an immediate period of financial austerity—will continue to determine the level of regulatory support.

Q. *How does Standard & Poor’s assess uncompensated reductions in the regulatory support or incentives that were promised to a project at the outset?*

A. We anticipate—but do not automatically assume—that the support and incentives available at the start of a project will be sustained in line with the original documentation, which usually means over the life of the transaction. We view recent uncompensated revisions as evidence that there is an increased risk of future retroactive changes, and take this into account when assigning a new rating in a particular legislation.

In evaluating the remedies a government or regulatory body puts in place to compensate for reductions in support for projects that are already operational, we focus on their impact on the credit quality of the transaction. First, we assess how the reduction in support affects the project’s ability to meet its debt service in full and on time. We then analyze whether the remedies will restore cash flow to the level expected at the outset of the project in each and every debt service payment period, or whether they aim only to restore the expected return over the life of the asset. While the former would preserve the project’s credit quality, the latter may not.

Q. *Does Standard & Poor’s apportion a similar level of regulatory risk to all renewable energy projects in a given jurisdiction, irrespective of fuel source?*

A. Not necessarily. For renewable energy projects in the same jurisdiction, we take into account each separate renewable energy source (wind, solar PV, solar thermal, or biomass, for example) and its specific regulation. Different regulations for different technologies or fuel types normally reflect variations in production costs and growth targets. These factors translate into different levels of sustainable financial support and, hence, variations in credit quality.

For example, we observe that solar PV projects in Spain accounted for about 37% of the almost €7 billion in total subsidies granted to renewable energy projects in 2010, compared with about 2% for solar thermal (see table 2). This may explain why the regulatory changes Spain implemented at the end of 2010 were more onerous for solar PV projects than for solar thermal projects. Furthermore, solar thermal technology lags considerably behind that of other renewables like wind or solar PV. This highlights to us that the regulatory support available to solar thermal projects in Spain is more sustainable than that for solar PV projects.

On the other hand, in most EU countries, wind projects account for a higher share of electricity generation than do other renewable energy sources, while receiving a considerably lower share of financial support. This makes wind less demanding on the public purse and its support more sustainable, in our view. **CW**

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Credit FAQ

How Electricity Market Reform Could Affect The Ratings On U.K. Generators

The U.K. government's carbon budget for the period 2023 to 2027, announced on May 17, 2011, proposes to cut Britain's carbon emissions by 50% from 1990 levels in support of the existing, legally binding target of an 80% cut by 2050. In Standard & Poor's Ratings Services' opinion, this places the U.K. at the forefront of global efforts to combat climate change. What's more, we believe it reinforces the government's stance regarding the need for urgent action on proposals for electricity market reform (EMR). This reform is aimed at delivering secure supplies of low-carbon energy cost effectively, while providing a measure of certainty for investors.

Even without taking into account the latest carbon budget proposals, the investment challenge for the U.K. power sector to meet the government's emissions-reduction target is daunting. According to the energy regulator, the Office of the Gas and Electricity markets (Ofgem), about £200 billion of investment will be needed in the energy industry over the next 10 years to ensure that the U.K. meets its carbon-reduction targets, while maintaining security of supply in the face of capacity closures and rising demand. Of the £200 billion, about £110 billion will be required specifically for new electricity generation and transmission assets—more than twice the level of investments made in the last decade.

The government believes that, in a globally competitive market for capital, attracting sufficient long-term investment at an acceptable price for consumers can only be achieved through a fundamental reform of the market. A particular concern in this

regard is the need to stimulate investment for new, low-carbon generation capacity—primarily renewables, nuclear, and CCS (carbon capture and storage)—that can generally be achieved only with some form of governmental or regulatory support.

In this FAQ, we answer investors' frequently asked questions on EMR and how it might affect ratings in the sector, following the government's White Paper published July 12, 2011, that provides detailed legislative proposals in support of the reform.

Q. *What are the main components of EMR?*

A. As we understand the EMR Consultation Document, the government's preferred electricity market framework will comprise four main elements:

- Feed-in tariffs (FITs). These are long-term contracts that provide stable and predictable revenues for investors

in low-carbon generation, including renewables and nuclear. The government's preference is for a contracts-for-difference (CfD) model, whereby generators sell electricity into the wholesale market, and receive a top-up payment from the government (or government agency) for the difference between the wholesale price and the agreed tariff level. Investors are effectively guaranteed a fixed price over a 15- to 20-year period, and low-carbon generators are no longer exposed to wholesale power price risk. The government anticipates that FITs could be in place from 2013. For renewables specifically, the FITs will replace the renewable obligation certificates (ROCs) from 2017.

- Capacity payments. These are targeted payments to ensure a sufficient capacity cushion as the proportion of intermittent and inflexible low-carbon generation increases.
- Carbon price support. This is a tax on the carbon content of fossil fuels used in generating electricity, which should lead to higher power prices, and thereby increase support for investment in low-carbon generation sources such as renewables and nuclear power.
- An Emissions Performance Standard (EPS). This standard places an absolute limit on the amount of carbon that new coal-based generators can emit. We understand that the EPS will be set at a level that precludes the construction of new coal-fired power stations, unless fitted with carbon abatement technology.

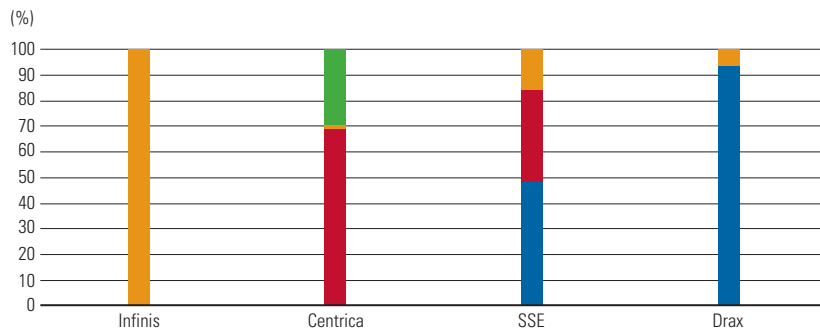
Q. *How might EMR affect the creditworthiness of rated European utilities?*

A. In our opinion, the potential consequences of EMR on the credit quality of rated European utilities (*see table*) are limited in the near term. This is because the reform will not be implemented until 2013 at the earliest, and issuers will need time to firm up their investment plans. In the longer term, however, and once the new generating capacity is operational,

Attracting sufficient long-term investment at an acceptable price for consumers can only be achieved through a fundamental reform of the market.

Electricity Generation Mix By Fuel Source For Selected U.K. Utilities In 2010

■ Coal ■ Gas ■ Renewables ■ Nuclear



© Standard & Poor's 2011.

we believe that EMR could reduce business risk for low-carbon generators, and increase business risk for the generation activities of those utilities that rely on fossil fuels.

Overall, we think the credit profiles of foreign-owned utilities will be largely influenced by the activities of their parent companies. Of the independent generators operating in the U.K., we consider Infinis PLC (B+/Stable/—) to lie at the lower end of the carbon emissions spectrum, followed by Centrica PLC, then Scottish and Southern Energy PLC (SSC; both rated A-/Stable/A-2). At the opposite end of the spectrum is Drax Power Ltd. (BB+/Stable/—), the coal-fired generator. In our view, the overall effect on rated utilities, if any, will depend on the extent to which they increase their financial risk in order to fund their investments.

Q. *Why might EMR change Standard & Poor's view on business risk for U.K. generators?*

A. As stated above, we believe that, all else being equal, low-carbon generators might experience a reduction in business risk. This is because their renewable and nuclear output from new plants built under EMR arrangements will be governed by the FIT, which will result in relatively stable and predictable cash flows. Power generated from fossil fuels (mainly coal, gas, and oil), on the other hand, will continue, under EMR, to be sold on the volatile wholesale markets without any price support, and will be subject to rising environmental and regulatory costs.

We note that electricity from renewable sources (not nuclear) is already supported by the existing system of ROCs. However, while ROCs provide a financial incentive through premium pricing, the power sold remains exposed to movements in market prices. We note that ROCs will remain in place for existing renewable projects, and potentially for new projects, until 2017.

Q. *How would you compare the business risk of generation under the FIT mechanism with that of regulated networks?*

A. While we believe that low-carbon generation under EMR would lie at the low-risk end of the generation spectrum, we are unlikely to view it as being quite as low-risk as network activities. Networks are natural monopolies that will, in our view, continue to be protected by direct and formal regulation through Ofgem. Generation, by contrast, will remain a competitive activity that, in our opinion, will be exposed to a greater degree of political risk.

We think that the FIT scheme will create a material direct cost for the government that could ultimately prove unsustainable, and we have seen support for renewables schemes wane in other European countries. That said, we understand that under EMR, political risk might be mitigated by the fact that the FITs with CfDs will be governed by long-term, contractually binding, private contracts. The enforcement of these contracts might be immune to subsequent regulatory change.

A second notable difference between renewables generation and regulated networks is that renewables output is subject to weather conditions, which will result in some cash flow volatility even if prices are fixed. By contrast, the regulatory framework for network activities in the U.K. currently ensures that network operators are not exposed to any form of volume risk.

Q. *Which utilities does Standard & Poor's believe stand to benefit most under EMR in terms of lower business risk?*

A. Based purely on the current mix of independent generators (*see chart*), we believe Infinis' business risk would be best positioned under EMR because the company is active exclusively in generating electricity from renewable sources (landfill gas, wind, and hydro). Centrica would be quite well positioned because of its existing nuclear capacity through British Energy Group PLC (not rated),

that it acquired in 2009, and its focus on gas-fired generation which—while emitting carbon—has lower carbon intensity than coal. Centrica also has a growing wind portfolio and the potential to participate in the construction of a new nuclear plant through its partnership with EDF Energy PLC (EDF; A/Negative/A-1). We consider SSE as slightly less favorably positioned than Centrica because about one-half of its output is coal-based. However, we note SSE's established position in renewables (mainly hydro and wind), and its large wind project pipeline that we anticipate will start generating significant cash flows in the near to medium term. We view Drax as less well positioned among the independent generators because of its focus on coal, and its limited downstream integration. That said, the company has stated its ambition to significantly expand its generation from biomass, whether dedicated or through co-firing with coal.

We would stress that our overall view of business risk for a particular utility takes into account a wide range of factors other than the generation mix. Such factors include the degree of vertical integration with the supply business; the relative cash flow contribution of generation, networks, and supply; the stage of development of the low-carbon generation portfolio (since business risk is likely to increase during the initial construction phase); the generation fleet's age, efficiency, and operational track record; and the effect of the highly competitive U.K. retail market on the supply business, if any.

Q. *Does Standard & Poor's believe that increased financial risk could offset any reduction in business risk as utilities fund their investments?*

A. Yes. An increase in financial risk could potentially more than offset any reduction in business risk if a company raises debt to fund its investments, even in instances where we regard those investments as supporting its business risk profile.

We understand that, ultimately, the costs of EMR will be borne by the consumer; Ofgem estimates that bills could rise by 14% to 25% between 2010 and 2015 to fund the estimated £200 billion of investment required. However, there is no direct link between the tariff received by the supplier and the investment made by the generator. In addition, there is likely to be a time lag between the utility raising debt to construct new generation capacity and offsetting the effect on credit ratios through revenues from the investment. For large-scale or technologically advanced projects such as offshore wind farms, there is also a significant construction and performance risk.

We believe that these effects will be amplified for new nuclear build, because of the very high capital cost relative to other forms of generation, and the long lead times between development and operation of the plant.

We note that rated utilities have limited headroom in their current ratings to accommodate an increase in financial risk. Vertically integrated issuers such as SSE and Centrica aim to maintain ratings in the 'A' category because their large investment needs require that they maintain good access to the debt markets. SSE's headroom is relatively limited at this time because ratios are under pressure from construction costs associated with its large wind project pipeline, which is only now starting to generate

significant cash inflows. Centrica has a more comfortable degree of headroom currently, but we anticipate that this might be eroded by the need to make upstream investments to maintain its vertical integration targets. (It has a target energy hedge ratio of 50% to 60%, defined as the proportion of gas and electricity needs that are supplied from either the company's own assets or certain long-term contracts.) In addition, we believe that Centrica is more likely to participate in new nuclear build, under its agreement with EDF.

Q. *How will the carbon tax affect electricity prices and, consequently, rated utilities?*

A. The government has confirmed that the carbon tax—or floor—will take effect from April 1, 2013, at £16 per tonne, and will rise to £30 per tonne by 2020. The tax, which will only apply to the power generation sector, will increase the marginal cost of fossil fuel used in generation, and therefore the price of wholesale power.

In our view, investors might doubt the long-term sustainability of the carbon floor policy because of the associated political risks. (The tax is subject to annual voting and review in parliament, and it could, therefore, change or be removed on relatively short notice.) We believe that the FIT mechanism is likely to provide a greater incentive to

invest in low-carbon generation than the carbon tax. Although the FIT scheme is exposed to political risk, we consider this risk to be lower than for the carbon tax due to the longer term, fixed nature of the CfD contracts.

We believe that the carbon tax is likely to affect the profit margins of rated utilities, depending on their generation mix and the prevailing merit order of different fuels. Prevailing wholesale electricity prices are determined by the most expensive form of generation that is meeting demand at any point (deemed the price-setting, or marginal, plant), which can be either gas or coal. As the carbon tax rises we expect coal to increasingly become the price-setter, resulting in higher profit margins for generators using other fuels.

Of the utilities that we rate, Drax is in our opinion the most exposed to rising carbon costs. To a large extent, we already factor this exposure into our current ratings on the company, and in our assessment of its weak business risk profile.

Q. *Could the Fukushima nuclear incident derail EMR?*

A. This would be unlikely, in our view. In line with other countries, the U.K. has decided to review the implications of the recent nuclear crisis in Japan on its existing, and planned, nuclear capacity. In an interim report published on May 18, Michael Weightman, the

Rated Utilities With Electricity-Generating Operations In The U.K.

	Corporate credit rating*	Business risk profile	Financial risk profile	Rating methodology†	Owner
Centrica PLC	A-/Stable/A-2	Strong	Intermediate	Independent	Listed§
Scottish and Southern Energy PLC	A-/Stable/A-2	Strong	Intermediate	Independent	Listed§
Drax Power Ltd.	BB+/Stable/—	Weak	Intermediate	Independent	Listed§
Infinis PLC	B+/Stable/—	Fair	Highly leveraged	Independent	Private
E.ON U.K. PLC	A/Stable/A-1	Excellent	Intermediate	Equalized	E.ON AG
EDF Energy PLC	A/Negative/A-1	Excellent	Significant	Equalized	EDF S.A.
Scottish Power Ltd.	A-/Negative/A-2	Strong	Intermediate	Equalized	Iberdrola S.A.
International Power PLC	BBB-/Stable/—	Satisfactory	Significant	SACP + 1 notch	GDF Suez S.A.

*As of May 24, 2011. †Whether assessed by Standard & Poor's independently, or within the framework of the utility's owner, or other consideration. §Listed on the London Stock Exchange. SACP—Stand-alone credit profile.

HM chief inspector of nuclear installations, states that the U.K. does not need to curtail its investment in new nuclear capacity. This is because the nature of the risks, and the designs of existing and proposed reactors, are different to those in Japan. Mr. Weightman does, however, make 25 recommendations on how safety might be improved. A final report is due in September.

We are not surprised by the outcome of Mr Weightman's interim report, because the urgent need for low-carbon generation capacity in the U.K. cannot, in our view, be met by renewable energy alone. We also note that public sentiment toward nuclear power is significantly more supportive in the U.K. than in many other European countries: A survey earlier this month by Populus Ltd., a U.K. research company, found that more than eight in 10 people were either fully supportive of nuclear power as the best way of tackling climate change, or thought it might have a role to play in the U.K.'s future energy mix.

Nevertheless, the Weightman report's recommendations suggest that there may now be delays in constructing new nuclear capacity, and that there might be additional safety-related costs for the generators (*see also "Japan's Nuclear Crisis Could Have Lasting Effects For European Nuclear Operators," published March 16, 2011, on RatingsDirect on the Global Credit Portal*). Higher costs might in turn require an upward adjustment in the tariff level for CfD's that have not yet been set, to ensure that investors or utilities are given a similar—or at least sufficiently attractive—return.

Q. Is EMR a 'done deal'?

A. No. The White Paper has confirmed that the government's intentions are unchanged since the consultation process, and that the four pillars of EMR will be implemented. However, detail is still lacking on certain areas that we consider important, namely:

- The potential priority access and route to market for power generated under CfDs;

- The mechanics of centralized auctioning (if or when it's introduced);
- The credit quality of the government counterparty providing top-up payments;
- The potential to increase connections with Continental Europe;
- The potentially distorting effect of capacity payments on the wholesale price.

In addition, we believe that even if all measures of the EMR framework are implemented according to schedule, and the above areas are resolved, the government may still find it difficult to attract the scale of investment required. The balance sheets of the utilities are constrained, and the U.K. is competing globally for capital. New investors might find more attractive opportunities elsewhere. They might also consider political risks inherent in low-carbon support frameworks to be a disincentive to invest in the U.K. in the longer term.

Q. How do the Green Deal and the Green Investment Bank fit into EMR?

A. The Green Deal and Green Investment Bank are separate government initiatives, and are not formally part of EMR. The former provides additional support for energy efficiency, the latter for low-carbon investment.

Under the Green Deal, which is due to take effect in the third quarter of 2012, households and businesses will be able to take out loans from the private sector to pay for energy efficiency improvements in their homes or offices. The loans will then be repaid through their energy bills, which should be lower than they otherwise would have been, reflecting the efficiencies made. As a consequence, we believe that utilities might experience a reduction in consumption, although prevailing energy prices mean this may or may not be reflected in lower energy revenues.

Possibly more important from a credit perspective is the fact that utilities might actively participate in funding loans to their customers, and collecting the repayments through bills

charged. This could, in our view, lead to the utilities incurring additional working capital requirements that, if funded with debt, could result in a weakening of credit metrics beyond what we currently anticipate. We will monitor this development closely, as most rated utilities at present have limited balance sheet capacity.

The Green Investment Bank should also launch in 2012, to support funding for low-carbon projects deemed too risky by the private sector to fund on its own. We understand that initial public sector funding for the bank will total £3 billion, and that the government expects to leverage £15 billion of private sector investment, resulting in a capital base of £18 billion. In our opinion, there should be a limited effect on the credit profiles of rated utilities in the sense that any borrowings taken by the utilities from the Green Bank will be factored into our assessment of their financial risk profiles, as previously. We also understand that the funding might have equity-like characteristics, and might therefore not be weighted equally as conventional debt in our analysis. **CW**

Notes

- (1) Further details on the U.K. Electricity Market Reform Consultation Document can be found at <http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx>
- (2) Further details on the U.K. Electricity Market Reform White Paper can be found at "http://www.decc.gov.uk/en/content/cms/legislation/white_paper/emr_wp_2011/emr_wp_2011.aspx".

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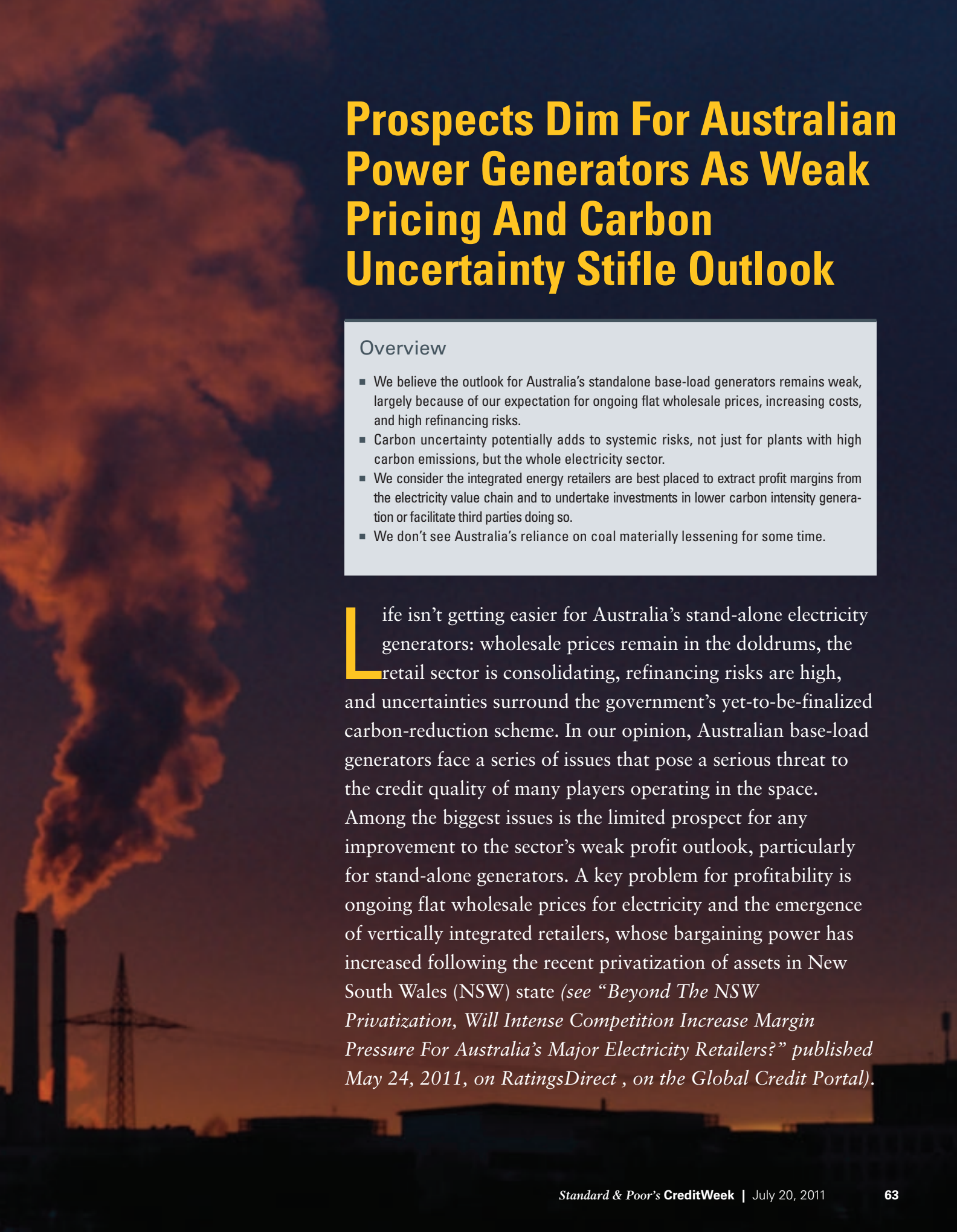
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Prospects Dim For Australian Power Generators As Weak Pricing And Carbon Uncertainty Stifle Outlook

Overview

- We believe the outlook for Australia's standalone base-load generators remains weak, largely because of our expectation for ongoing flat wholesale prices, increasing costs, and high refinancing risks.
- Carbon uncertainty potentially adds to systemic risks, not just for plants with high carbon emissions, but the whole electricity sector.
- We consider the integrated energy retailers are best placed to extract profit margins from the electricity value chain and to undertake investments in lower carbon intensity generation or facilitate third parties doing so.
- We don't see Australia's reliance on coal materially lessening for some time.

Life isn't getting easier for Australia's stand-alone electricity generators: wholesale prices remain in the doldrums, the retail sector is consolidating, refinancing risks are high, and uncertainties surround the government's yet-to-be-finalized carbon-reduction scheme. In our opinion, Australian base-load generators face a series of issues that pose a serious threat to the credit quality of many players operating in the space. Among the biggest issues is the limited prospect for any improvement to the sector's weak profit outlook, particularly for stand-alone generators. A key problem for profitability is ongoing flat wholesale prices for electricity and the emergence of vertically integrated retailers, whose bargaining power has increased following the recent privatization of assets in New South Wales (NSW) state (see *"Beyond The NSW Privatization, Will Intense Competition Increase Margin Pressure For Australia's Major Electricity Retailers?"* published May 24, 2011, on RatingsDirect , on the Global Credit Portal).

Making matters worse, the generation sector is potentially facing more pain from the Australian government's pending introduction of a carbon-abatement scheme. Although the government is yet to announce final details on pricing and compensation, evidence suggests that shareholder and investor sentiment for investments and funding for the sector is wavering ahead of the industry's move toward a lower carbon-intensive environment. Carbon-intensive brown-coal generators, in particular, are facing a challenging period as they approach some sizable refinancing tasks while grappling with issues associated with market-transition risks.

On the plus side for stand-alone coal-fired generators, we don't think any move toward energy sources with lower carbon intensity will be rapid. Indeed, we believe coal—which now accounts for more than 80% of generation output in the national electricity market (NEM)—will remain Australia's largest source of electricity for some years. In our view, there is a limited installed capacity to enable a ready transition to energy sources with lower carbon intensity. Nevertheless, the uncertainty regarding prospective economic asset

lives heightens investment risks for both debt and equity investors in this space. These issues also combine to dampen appetite for investments in the new generation required if a transition to an electricity sector with lower carbon intensity is to occur while still maintaining security of supply.

Flat Wholesale Prices Point To Problematic Outlook For Stand-Alone Generators, But Retailers May Tap Margin-Capture Opportunities

The wholesale price story of the past 10 years, excluding the drought-induced peak in 2007, is one of generally flat pricing for most markets in Australia's NEM. Average spot pool prices for electricity have been consistently below A\$40 per megawatt hour (MWh) in the past decade (*see chart*). Although we consider the average spot price to be a guide to the pricing able to be achieved, we note that actual average prices are likely to be somewhat higher. This is because most power stations contract much of their output at prices above the spot price (reflecting in part the foregone opportunities to achieve higher prices that inevitably occur during periodic

weather-induced events, as well as recovery of expected increases in operating costs). This flat pricing trend, which we believe is more reflective of short-run marginal costs (i.e. excluding return on capital), has come at the same time as rising costs for power stations in areas such as labor. Consequently, we believe base-load generators have likely experienced margin and cash flow compression in the past few years. Accordingly, we consider this pricing environment has increased generators' reliance on capturing wholesale price spikes for uncontracted load to maintain profitability, thereby entrenching volatility of profitability.

Exacerbating the flat price trend has been the relatively mild Australian 2010 to 2011 summer, which reduced load demand (mainly due to lower use of air conditioning) and meant that the traditional summer price spike was far more subdued than in recent years. For those privately owned power stations that are highly leveraged, such as Loy Yang A (LYA; not rated) and Hazelwood (not rated), we believe creditworthiness is likely to have further deteriorated, partly because of higher debt margins from recent debt-refinancing tasks. The upshot is that returns for shareholders in companies such as LYA and Hazelwood have been under pressure. We note comments by LYA's 14% owner Transfield Services Infrastructure Fund (not rated) in its recent half-year results that it expects no cash dividend from its investment in LYA for at least three years while LYA pays down project level debt. In our view, the trading difficulties of the former Alinta Energy Group (previously Babcock & Brown Power) were in part due to weaker-than-expected wholesale prices over a long period of time, which meant that its capital structure was ultimately too highly leveraged relative to cash flow to retain lender support.

The low price environment has also affected state-owned generators. We believe the recent restructuring in the state of Queensland, where the number

We don't think any move toward energy sources with lower carbon intensity will be rapid.

Table 1 **Near-Term Debt Maturities Of Victorian Stand-Alone Brown Coal Generators**

Power station#	Approximate debt amount*	Near-term maturity	Carbon intensity (tonnes CO2/MWh)
Loy Yang B	A\$1.1 billion	June 2012	1.2
Hazelwood	A\$0.7 billion	June 2012	1.5
Loy Yang A	A\$0.5 billion	Late 2012	1.2

*Detail for Loy Yang A and Hazelwood sourced from public reports. Note: Yallourn is not included in this list, as we see this as part of the TRUenergy corporate group, although we believe that Yallourn's carbon intensity is about 1.4 tonnes CO2/MWh; hence, creditworthiness is based more on group cash flow rather than just the power station. MWh—Megawatt hours.

of generator groups has decreased to two from three (effective from July 1, 2011), partly reflects an effort to preserve asset values by focusing more on cost savings and operating synergies in a weak wholesale price environment. One of the factors cited in the Queensland government review of its state-owned generators was the emergence of vertically integrated retailers and the shift in bargaining power to these entities—a phenomenon even more noteworthy following the recent privatization of retail power assets in the state of NSW.

NSW experienced relatively higher prices in 2010 (average spot prices rose by 23% to A\$52 per MWh), largely due to several extreme weather events. Although this likely improved profitability of the generators at the time, we believe the ability of the two unsold gentrader contracts in NSW (attached to Macquarie Generation and Delta Coast) to continue to benefit from price peak events is problematic. Given the electricity retail sector is now dominated by large incumbents who generally have access to their own generation or hedging contracts, the magnitude of price peaks could be lower, even if their rate of occurrence is unchanged. In our view, this leaves the profitability of the remaining two unsold generating groups more exposed to the weaker prices that prevailed in the early and middle parts of the past decade.

We note the state of South Australia is something of an exception to the other mainland NEM states, which are biased to coal generation. The South Australian generation fleet is biased to gas-fired generation and renewable sources of energy, particularly wind (869 MW of capacity and 22% of output for the year to June 30, 2010). In our view, South Australia serves as a microcosm to highlight the advantage enjoyed by integrated players in the NEM. For example, AGL Energy (BBB/Stable/—) benefits in its capacity as a major retailer and owner of a significant base-load generation source (Torrens Island Power Station). In times of constrained supply, such as heat waves (which can see load demand

double), AGL Energy is able to protect its retail margins through the natural hedge provided by its generation and also sell into the wholesale market at higher prices.

Excluding Carbon Costs, There Are Limited Near-Term Catalysts For Wholesale Price Rises

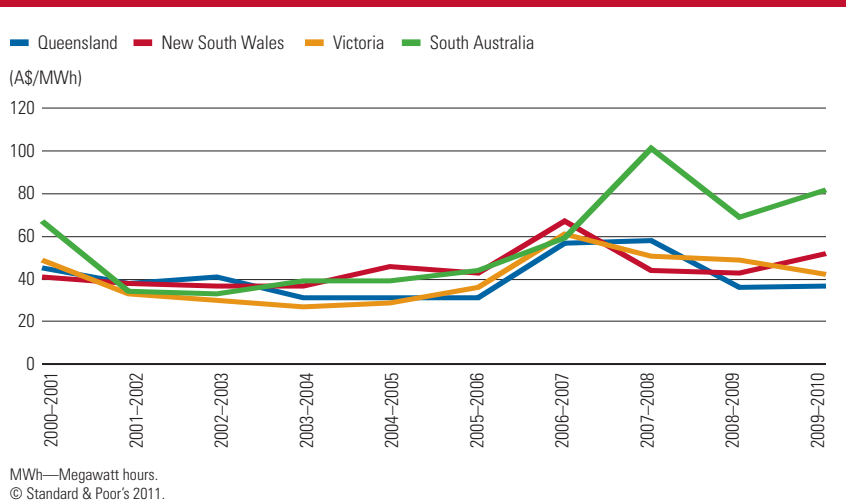
At present, we see limited short-term catalysts for wholesale price uplift in the NEM (excluding any rises that flow from the introduction of a carbon price, which for most generators is more about to what extent this can be recovered from end users). Accordingly, our base-case model assumes that average prices will remain unchanged for the next few years at least. The key caveats to this assumption are: to what extent any carbon scheme lifts prices; what extent the generators with higher carbon intensity continue to be dispatched; and the extent to which the newer coal generators, which tend to be of lower carbon intensity, can capture any carbon tax loading. Clearly, any carbon scheme that induces an immediate or near-term shutdown of a major plant could change the supply-demand balance such that wholesale prices lift; however, whether the NEM has adequate non-coal-based generation sources for this to occur is debatable.

Our flat expectations for wholesale prices in the short-to-medium term compares to some market projections that invariably project average prices trending up well into the A\$40/MWh level and beyond (not least due to expectations that prices would at least hold in real terms, reflecting input cost increases). The two primary drivers of wholesale price increase expectations in the market have been:

- Continued tightening of underlying demand and supply (principally from economic and population growth), particularly in the absence of material new base-load generation coming on stream; and
- Reversion to price levels that include adequate returns for capital (i.e. long-run marginal-cost levels, as opposed to current average prices, which are more reflective of operating costs).

We don't doubt that these factors will at some point drive an increase in prices toward levels that reflect long-run marginal costs of new generation entering the market, particularly as the demand growth approaches the system operators' supply reserve margins in the mid to late part of this decade. Contrary to some of these market expectations, however, we believe that empirical evidence shows

Australian Mainland Volume Weighted Average Spot Electricity Prices (MWh)



that these price drivers are yet to make their way into the market.

In our view, factors weighing on the average wholesale price include:

- Increased integration of retail and generation, with retailers increasingly having access to peak generation. For example, following the construction of the Mortlake plant (550 MW), Origin Energy Ltd. (BBB+/Stable/A-2) will have direct access or control of some station offtake in each mainland state.
- Increased retail market consolidation following the NSW privatization, with just three large creditworthy (investment-grade) buyers.
- Continued availability of “ramp up” gas in Queensland as the coal-seam gas to LNG projects develop their resource base (although gas supply could move into deficit following project commissioning, or prices are likely to escalate toward export parity, as per the Western Australian experience).
- The renewable-energy target of sourcing 20% of electricity from renewable power by 2020 is likely to displace thermal base-load power’s market share, given the

negligible short-run marginal cost of renewables. This may lead to surplus capacity among large-scale thermal plants, although older plants are likely to be retired, mitigating this impact.

- Meeting the expected greater growth in peak demand of about 2.5% versus base-load growth of about 2.0% (according to the Electricity Supply Association of Australia), adding incremental supply to the network, particularly by the integrated retailers.
- Demand management programs, particularly through smart meters, that lead to reduced demand or at least a flattening of the load profile may temper some of the wholesale price spikes and potentially lower per capita demand. We assume that the business case of these programs is robust, given the approval of significant investment in Victoria to date.

We believe the weak outlook for wholesale prices is a factor enticing generators to enter the retail market in order to ensure dispatch of their plants and capture some margin from incumbent retailers. For example, Alinta

Energy has stated that it has plans to enter the retail market.

Opportunities For Retailers, But Increased Volatility And Competition Remain Serious Threats

We believe the pricing environment has been positive for retailers and enabled margins to be maximized. However, real margin expansion will continue to be tempered by intense competition between retailers, particularly in the state of Victoria (where prices are deregulated). Competition seems to be intensifying following the NSW privatization, which saw a large transfer of customers to just two incumbents. All players are now seeking to establish their “natural” market share by increasing competition, which has led to high customer churn rates (*see “Beyond The NSW Privatization, Will Intense Competition Increase Margin Pressure For Australia’s Major Electricity Retailers?” published May 24, 2011*).

This competition, combined with the numerous—albeit random—occurrences of weather-induced wholesale price spikes above A\$300/MWh, may also depress retail profitability. At its most extreme, these factors may threaten business viability, especially if companies are not insulated from these events through contracts with generators or through derivatives. These volatile and difficult market conditions underpin our opinion that stand-alone retail businesses in the

This competition, combined with the numerous—albeit random—occurrences of weather-induced wholesale may also depress retail profitability.

Table 2 Coal Share Of Electricity Output 2009/2010

State	Total capacity (MW)	Capacity (MW)	1% decrease in coal capacity	NEM total generation (GWh)	Coal (GWh)	Coal output share (%)
Queensland	13,074	8,805	88	60,014	49,362	82
New South Wales & ACT	16,355	11,797	118	70,407	64,388	91
Victoria	11,023	6,555	66	56,436	51,454	91
South Australia	4,232	780	8	14,621	4,559	31
Tasmania	2,280	—	—	9,891	—	0
Total NEM	45,941	27,937	279	211,367	169,763	80

MW—Megawatts. MWh—Megawatt hours. GWh—Gigawatt hours. ACT—Australian Capital Territory.
Source: Energy Supply Association of Australia yearbook for 2011.

Australian market would be viewed as speculative-grade credit quality without adequate liquidity support.

In our view, the integrated retailers, especially the three largest—Origin Energy, AGL Energy, and TRUenergy (BBB/Stable/—), are best positioned to take advantage of the flat prices by virtue of having their own generation, particularly peaking plants. This integrated position enables margin capture from the whole value chain and protection from price spikes (by generating themselves or using the capacity as leverage in negotiating favorable derivative contracts). Moreover, this “end-to-end” attribute highlights the advantage of scale to drive down costs, in an industry that is inherently competitive to protect margins.

Although investment-grade retailers invariably hedge exposure to wholesale price volatility, this doesn’t come without cost. Arguably, it is difficult to hedge all exposure, and there will be times when losses are made. For example, AGL Energy announced in February 2011 that a confluence of “extreme abnormal” weather events was the primary cause of a reduction in the company’s fiscal 2011 net profit forecast by up to A\$35 million. This amount isn’t particularly material for the rating on AGL Energy, but it does highlight the potential loss severity and the advantage that integrated players of scale enjoy from having larger balance sheets to absorb such events.

Challenging Refinancing Tasks Await Some Stand-Alone Generators, As Pressure Mounts On Credit Quality

Another major pitfall of flat prices is the pressure this places on the credit-worthiness of generators and, consequently, lender appetite for the sector. This factor, combined with the uncertainty posed by the government’s yet-to-be-finalized carbon scheme (intended to be implemented by mid-2012), creates a challenging debt-refinancing environment for the stand-alone thermal generators, particularly the

more carbon-intensive brown-coal generators in Victoria (*see table 1*). A key challenge will be the terms and conditions that lenders will seek to implement to protect themselves against potential erosion in asset values over the long term. On top of this, we expect costs to continue to increase. For example, labor costs are likely to increase at least at the same level of inflation. For companies operating in the black coal and gas space, there are also increasing fuel re-pricing risks.

In our view, Hazelwood is the most exposed generator to refinancing risk, due to the size of the company’s near-term debt maturities, the relative age of the power plant (correlating to lower operating efficiency), and its carbon intensity. Loy Yang A is also highly exposed, mostly due to what we understand are high levels of debt. The short-term refinancing risk of Loy Yang B (the main asset of LoyVic Pty Ltd.) is ameliorated to some extent by the benefits from state hedge arrangements (established to support the Portland and Point Henry aluminum smelters), giving some earnings certainty for a few more years; the company also benefits from lower debt than its Victorian peers and a superior operating-cost profile, reflecting the younger age of the plant. That said, we believe that new debt terms are likely to be increasingly onerous for Loy Yang B—especially if the carbon legislation is passed, while the loss of the aluminum smelter supply contracts to Loy Yang A from 2014 is likely to increase earnings risk.

Aside from carbon-pricing risks, thermal generators also face fuel-transition risks. For example, black-coal generators face a re-pricing of black-coal contracts to levels more akin to export parity (we note that thermal coal prices have increased to about US\$130 per tonne, from about US\$50 per tonne in the mid-2000s). Gas-fired generators face fuel price uplift toward export parity once the east coast of Australia becomes an LNG exporter, which is

forecast to occur sometime in the middle of this decade.

Of the integrated energy companies operating in Australia, we see Origin Energy—through its Eraring Energy gentrader contract—as the most-exposed company to any fuel re-pricing, given its coal contract run-off from 2012. To what extent the NSW government’s Coborra mine development commitment as part of its gentrader privatization mitigates this upward pressure remains to be seen.

Carbon Risk Heightens Sector Uncertainty

The government’s mid-2012 timetable for the introduction of a carbon scheme means we expect some clarity about the details of any scheme in the near term, if only due to legislative milestones that need to be met. Until such a scheme is implemented and participants are able to apply the lessons learned from active participation in any market mechanism, we think that execution risks will remain high.

In our opinion, the carbon-abatement issue and credit risks can be broken down into two parts:

- Short-to-medium term: Maintaining energy supply system reliability and security, thereby minimizing systemic risk, and hence credit risk; and
- Medium-to-long term: Providing economic incentives to encourage the transition to a lower-carbon-intensive fuel source. Closely related to this issue is the uncertainty over which market players have the willingness, and access to the capital, to undertake this investment.

Plant Maintenance Is Key To Sustaining Plant Efficiency And System Reliability

In terms of energy market stability and, hence, credit stability, we believe an important element under any carbon scheme is that there is an orderly transition that does not undermine systemic security of energy supply.

We are concerned that uncertainty over a carbon scheme may tempt owners of plants already struggling

financially to defer expensive maintenance tasks. For example, major unit maintenance can cost as much A\$50 million to A\$70 million. Deferral of maintenance increases the risk of more forced power outages and may lead to more price volatility (which is sub-optimal for retailers, especially smaller niche players, as it increases vulnerability to catastrophic price events). Accordingly, we consider a key element of system reliability and security to be the ability of the generators to continue to carry out key long-term maintenance programs to maintain, and indeed even incrementally upgrade, the capacity of the existing plant. Hence, any government-imposed scheme that increases financial pressure on the high-carbon-intensive generators (which are obviously most exposed to a decline in economic life) could be adverse for credit quality and potentially for all market participants.

level for coal plants when run well) and there are likely to be grid-upgrade costs as part of any connection.

The Transition To A Lower Carbon Future: Aside From The “Big 3,” Who Will Invest?

We consider generation plants to be very expensive relative to the enterprise values of the players in the Australian market. Accordingly, there are few entities that we believe have the capability to undertake the investment needed to transition to a lower carbon future. At the same time, we believe many entities may struggle to attract lender support to do so. For example, Origin Energy’s Darling Downs combined-cycle 630 MW gas-fired base-load plant commissioned July 2010 was estimated to cost A\$780 million when announced in June 2007. In simple terms, based on these costs, replacing Hazelwood (the most carbon-intensive plant in the

Australia. In our view, state governments have been trying to divest assets and let the private sector assume the investment risk. Also, we believe that state governments will likely balk at future developments in this sector because of the high costs.

For the country’s existing privately owned independent power producers (IPPs), there are substantial hurdles to inducing these entities to invest in any meaningful way and partake in the “gas as a transition fuel” future. One of the biggest challenges for new investment is achieving adequate returns in a volatile market without a guaranteed dispatch to a significant retail base. Even after the introduction of a known carbon regime, we believe that there is a high level of uncertainty there will be a match between a plant’s economic and physical life (of as much as 50 years), making it difficult for existing shareholders of IPPs to commit new capital. This is particularly pertinent for those IPPs that already have stretched balance sheets. Moreover, we believe it would be difficult to entice lenders to commit material debt levels to any investment without a robust offtake contract from a counterparty of sound creditworthiness (effectively AGL Energy, Origin Energy, or TRUenergy). In our view, the prospects for doing so are dampened by the refinancing and solvency issues besetting the IPPs exposed to market risk. Furthermore, we also struggle to see existing or new offshore players committing capital in the absence of more market certainty. However, compensation mechanisms that promote voluntary closure of high-carbon plants in exchange could spark new investment.

In our view, the field for any new material investment in the medium term is biased toward the “big 3” integrated companies—AGL Energy, Origin Energy, and TRUenergy. Realistically, we believe it is these three groups that have the capacity, and possibly the willingness, to make the very large capital commitments

Although governments clearly have the capacity to invest in generation, we believe they no longer have the willingness to do so.

The key challenge associated with the proposed transition to a lower carbon future in Australia is the NEM’s existing heavy reliance on coal (see table 2). According to our rudimentary calculations, just a 1% decrease in aggregate coal capacity would result in a loss of 279 MW. In simple terms, replacement of this capacity with renewable power such as a wind farm could cost as much as A\$660 million (based on AGL Energy’s Aug. 12, 2010 announcement of its A\$1 billion 420 MW Macarthur wind farm). We believe this calculation likely understates the total cost involved, given that wind farms typically run at capacity factors of about 30% (compared to well into the 80%

NEM) with a gas-fired base-load plant may cost as much as A\$2 billion, plus gas supply infrastructure. The 1,600 MW of capacity at Hazelwood supplies about 6% of the output of the NEM. That said, we note that the Australian dollar has appreciated significantly since 2007, which would likely bring down the equipment costs associated with replacement.

Although governments clearly have the capacity to invest in generation, we believe they no longer have the willingness to do so. We note that about half of the country’s generation fleet remains under state government control through state-owned enterprises, reflecting government’s historical role in building most plants in

necessary to sequentially replace the high-carbon intensive plant. Even so, the scale and expense of these projects are such that any investment would likely be made over many years. The significant expense means that it is likely the big 3 will not undertake all investment, but facilitate third parties through contractual arrangements or co-investments.

For material investment to occur, we consider the economic incentives would need to significantly improve on the present market dynamics. Currently, we see the big 3 generally focused on adding peaking and intermediate generation to their portfolios rather than materially looking to add to base load (for example, Origin Energy's A\$640 million 550 MW Mortlake OCGT power station, TRUenergy's A\$350 million 400 MW CCGT Tallwarra plant, and AGL Energy's proposed Dalton plant of 250 MW to 780 MW). The integrated retailers' current goal is to enhance portfolio options and preserve retail margins rather than substantially increase capacity. Regardless, a key element in any transaction will be an underlying need to transfer any carbon costs through to the retail end user to protect margins.

Meantime, we view the recent purchase of base load as part of NSW privatization as somewhat different, as this investment was about obtaining load for a "big bang" acquisition of retail customers—something that we believe is unlikely to occur in the NEM again.

Rising Gas Fuel Costs Could Allow Coal To Remain A Key Power Source For Some Time To Come

Under any proposed carbon scheme, Victorian brown coal plants—as the most carbon intensive—are arguably the most at risk of economic redundancy. However, we believe that coal will remain an important source for the NEM for some time to come, given Australia has limited installed capacity to enable any rapid substitution to lower carbon base load. Gas is the oft-mooted "transition" fuel to a lower

carbon future. For this to come to pass, we believe a key element moving gas-fired plants down the dispatch merit order and replacing coal as a base-load power source is the price of gas. Although long-term gas contracts have historically been available in Victoria for about A\$3.00 to A\$3.50 per gigajoule (GJ), we believe prices are on the up. The development of a successful LNG export industry in Queensland is likely to see gas pricing move toward export parity pricing. Western Australia, notwithstanding the different market structure, serves as an example of where domestic gas prices have risen over time despite an expansion of gas production, as producers look to service more lucrative export markets. For example, the Western Australian parliamentary inquiry into domestic gas prices in March 2011 reported the average price of new domestic gas contracts in Western Australia (in 2009 and 2010) from the north-west shelf to be in the range of A\$5.55 to A\$9.25 per GJ. This compares to an average price of A\$3.70 per GJ (factoring in all the legacy gas contracts).

If gas prices along Australia's east coast move in a similar manner to those of Western Australia, a significant increase in gas fuel costs would not surprise. A recent research paper by AGL Energy reported that the Victorian brown-coal fleet has the lowest short-run marginal cost at A\$5 per MWh compared to base-load gas plant of A\$30 per MWh (at gas prices of A\$4.50 per GJ). Similarly, black-coal prices in NSW and Queensland are also forecast to increase due to exposure to export pricing. Accordingly, notwithstanding any carbon-abatement scheme, the newer brown-coal generators (with carbon intensities closer to 1.2 tonnes CO₂/MWh) may well be in business for some time to come, just on a comparative marginal-cost basis.

If a carbon-abatement scheme favors the economics of gas power stations over coal, we believe that Origin Energy is the best placed of the

three major retailers to take advantage. This is because Origin Energy (unlike the others) has an extensive productive gas resource that the group owns and operates, and is already supplying its own needs.

We expect the mandatory renewable energy scheme to underpin rapid growth in the build-out of wind-generation sources, although we note that wind-farm development has recently stalled following the collapse in prices for renewable energy certificates. Undoubtedly, wind farms provide another important and alternative source of power for a lower carbon future. Nevertheless, we currently view wind as being more of a "swing" producer, given that its availability is not always subject to the owner/operators control compared with base-load energy providers. Therefore, provision of security of supply may mean there is still a role for some coal plants—at least in the medium term.

Credit Profiles Of Generators Remain Under Pressure

In our view, the medium-term future and associated credit profiles of Australia's power generators remains in a state of flux. The economic lives of stand-alone base-load coal plants may be reduced considerably under any transition to a low-carbon future, although the country's reliance on coal means we expect these plants to be around for some time to come, even though the financial performance of coal plants is likely to be further strained. From a credit perspective, we believe the integrated generation-retail businesses are in the best position to tackle the industry changes and investment risks. **CW**

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An Overview Of The U.S. Electric Car Market

Gaining, But In The Slow Lane

When gasoline prices reached \$4 per gallon in parts of the U.S. this spring, public attention again focused on America's dependence on foreign oil for domestic transportation needs. There were an estimated 250 million registered passenger vehicles on U.S. roads last year, roughly double the number in the early 1970s. That translates into 1.2 cars for every registered driver in the U.S., according to the Federal Highway Administration, a division of the U.S. Department of Transportation. It's no surprise, then, that passenger vehicles accounted for approximately 40% of all U.S. oil consumption as of November 2010, according to the U.S. Environmental Protection Agency (EPA).

Editor's Note: This is an introduction to the basics of electric vehicles and is the first in a series of articles exploring the electric vehicle's likely effects on the sectors we follow. Future articles will provide detailed analysis of the economics of electric vehicles, their expected growth nationally and globally, and the implications that electric vehicle adoption could have for the electric utility industry and the clean technology sector. Because U.S. transportation infrastructure depends heavily on gasoline taxes to support investment, we also explore the implications that widespread popularity of electric vehicles could have for the public financing of roads and highways.

Overview

- High gasoline prices and U.S. dependence on foreign oil have increased consumer and automaker interest in electric vehicles.
- Automakers are introducing electric vehicles with improved technologies.
- Various issues, ranging from charging infrastructure to pricing, mean that the electric vehicle market will grow slowly.

A new generation of electric vehicles is now stepping into this mix. For now, only two major automakers have introduced an electric vehicle in the U.S. Nissan started deliveries of its Leaf all-electric car in December 2010, and Chevy released the Volt, a plug-in hybrid, in January 2011. But key manufacturers plan to introduce more electric vehicle options in the next few years:

- An electric version of the Toyota Motor Co.'s Prius is planned for U.S. rollout in 2012. This plug-in version of the successful Prius hybrid is designed to run on electricity for 13 miles and then switch to its hybrid motor technology, which provides an

average fuel economy of 50 miles per gallon (mpg). Toyota has also partnered with Tesla Motors to develop an electric version of its RAV4, a compact SUV that is also targeted for release in 2012.

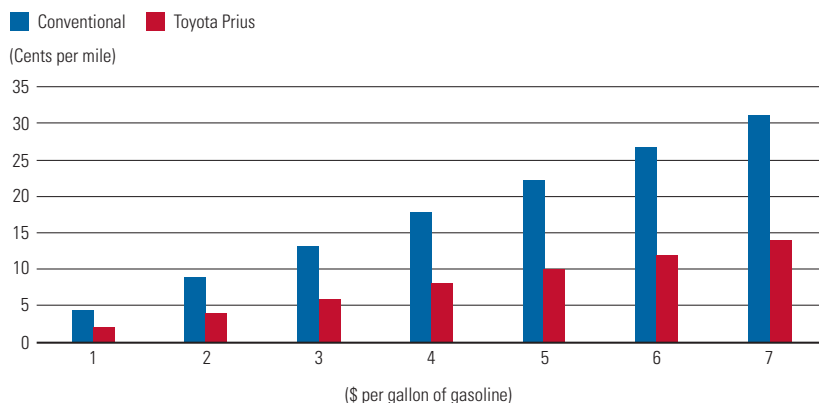
- Later this year, Ford plans to introduce an all-electric version of its Focus in 19 U.S. urban markets. The five-door hatchback is expected to be able to travel 100 miles before requiring a charge, and Ford has partnered with national electronics retailer Best Buy to sell a home charging system for about \$1,500.
- Mitsubishi expects to roll out a U.S. version of its i-MiEV later this year. Already available in Japan,

the i-MiEV is a compact two-door that will compete in the electric vehicle market on the basis of its low entry price: about \$27,990, or several thousand dollars less than Nissan's Leaf.

Electric cars have captured considerable media attention, and their launch coincides with the Obama administration's recently announced goal of putting 1 million electric vehicles on U.S. roads by 2015. This is a tall, perhaps impossible goal given today's starting point. This year, we expect automakers to sell 12.7 million light vehicles in the U.S., slightly fewer than the 13 million vehicles we estimate are needed for replacement. (See "Global Automakers And Truckmakers Should Benefit From The Global Recovery Trend," published June 23, 2011, on RatingsDirect, on the Global Credit Portal.) Electric car sales are likely to be just 5,000 to 10,000 of this total. And because cars tend to stay on the road for a decade or more, even widespread enthusiasm for electric vehicles will not translate into immediate material changes in the composition of the U.S. fleet.

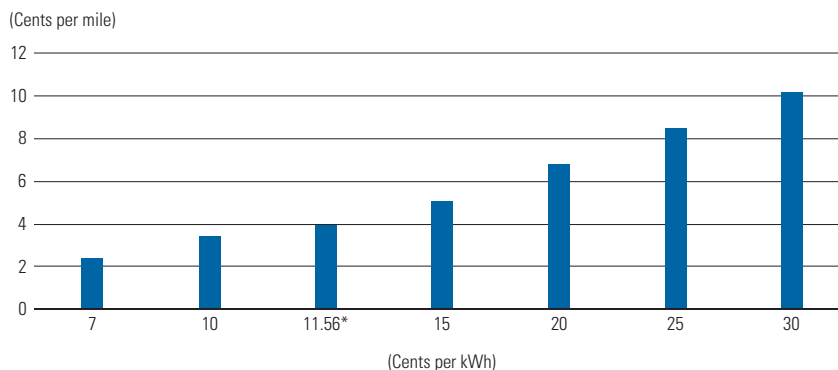
A key reason is that electric car options are more expensive: about \$10,000 to 15,000 more on a retail basis than an equivalent conventional vehicle, depending on whether the car is pure electric or an electric-gas hybrid and the car's particular features. Although a federal tax credit of \$7,500 narrows this gap, lithium-ion battery technology will need to improve to bring down the sticker price of a new electric car in the long term. But once purchased, the fuel costs of an electric vehicle are unambiguously lower than those of a conventional car. Other factors that may limit adoption include "range anxiety" (i.e., driver concern that the electric car will run out of electricity away from home), maintenance and reliability concerns, and that, at least initially, electric vehicle design will favor compact models. As Toyota aptly summarizes, electric vehicles

Chart 1 Fuel Costs For Conventional Car Versus Toyota Prius



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Chart 2 Fuel Costs For Battery Electric Vehicle



*U.S. average, kWh—Kilowatt hour.
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make sense for “certain customers, in certain geographic areas, with certain grid-mixes, with certain drive-cycles, and with access to charging.”

Minimal Credit Implications For The Auto Sector, Bigger Changes For The Power Sector Possible

These factors suggest that electric vehicles will be slow to develop. For the U.S. auto sector, the possibility that gasoline prices could spike to levels not seen in almost three years could result in declining overall vehicle sales and a shift in consumer vehicle preferences toward more fuel-efficient alternatives. Yet we don't expect electric vehicles to sell at levels high enough to make them a credit factor in our ratings on automakers over the short to medium term.

For the electric power sector, the immediate credit consequences are also modest due to our assumption that electric vehicle growth will be gradual. But for electric utilities and possibly merchant power companies that are eyeing the emerging market as a growth opportunity, there is certainly potential for electric vehicles to alter the power landscape. Some of the issues that electric utilities will have to grapple with are:

- Accommodating new vehicles in the electric distribution system, which may require upgrades and capital investment. Even if electric vehicles grow slowly, grid experts and utilities expect “clustering” to occur. That is, even if overall market penetration of electric vehicles is modest, adoption could be quite rapid in neighborhoods where income, commute patterns, and other demographics create pockets of electric vehicle owners who place a heavy demand on the distribution network. Utilities will need new tools to predict where these sub-markets develop and be prepared to make isolated investments in advance of new car purchases to ensure local reliability.
- Encouraging off-peak usage by introducing new pricing plans for electric

vehicles. Related to this issue is projecting how much new demand electric vehicles will create and ensuring that utility resource plans are able to satisfy this need.

- Evaluating new business opportunities that stem from electrification of passenger cars. Because most electric utilities are permitted to retain any profits from electric sales growth, some power companies and rival unregulated retail electric providers may get into the business of developing public charging stations or try to compete in other parts of the electric vehicle value chain.
- Integrating electric vehicles into growing mandates to reduce environmental emissions and lower carbon footprints. Even if a utility does not get involved in the electrification of cars for profit, it may still have a vested interest in their adoption. In California, for example, power producers are facing a state cap-and-trade market that will require them to reduce their carbon emissions over time. Robust adoption of electric vehicles could lessen both the price of carbon allowances that utilities must buy and help the state meet carbon milestones.

A Brief History Of The Electric Vehicle

Today's electric vehicles represent the U.S.'s third flirtation with the technology in the past 100 or so years. Electric cars dominated the late 19th- and early 20th-century car market because they did not require hand cranks to start and operated without the noise, smell, and pollution of early internal combustion engines. But cheap oil and the economics of mass-producing the internal combustion engine ended the electric car's first, brief ride by around 1900.

The next faltering steps came more than a decade ago when companies developed options in response to California's zero-emission vehicle regulations. Manufacturers deployed some 4,400 electric vehicles from 1996 to 2002, the most ubiquitous of which was

General Motors' EV1. It's not clear how many are still on the road.

The appeal of a passenger vehicle option that shields early adopters from high gas prices spurred the latest wave of investment in electric cars. The popularity of hybrid vehicles in key markets has conditioned consumers to accept alternative engines, while development of lithium-ion battery technology has reduced costs and improved performance substantially compared with the earlier nickel-metal hydride batteries. Although federal support for alternative vehicles has been modest to date, "cash for clunkers" schemes during the economic downturn illustrate how effective support can be to boost demand for new, fuel-efficient cars. If government support for electric vehicles grows, which could occur if Middle Eastern and Libyan unrest continue, electric vehicles could see a sustained push that accelerates their entry into the mainstream car market.

Hybrids, PHEVs, And BEVs Jockey For Position

Three major types of alternative vehicles are competing for market share:

hybrid gas-electric vehicles (hybrids), plug-in hybrid electric vehicles (PHEV), and pure battery electric vehicles (BEV), (*see table*).

Hybrids primarily rely on gas engines, but have electric motors, powered by stored energy, that essentially double fuel economy relative to a conventional combustion car of the same size. Hybrids can achieve fuel efficiency of 40 to 50 mpg under ideal conditions. (These conditions typically entail significant braking, which creates energy that is stored in the battery. At higher and consistent speeds such as highway driving, fuel efficiency declines.)

The hybrid is both a rival to emerging electric vehicles and a predictor of the adoption path for electric vehicles. Honda brought the first hybrid car to U.S. markets in 1999, and Toyota introduced the Prius the following year. Cumulative U.S. hybrid sales took nearly a decade to hit the 1 million mark in 2008, but just three years later, in June 2011, this figure doubled. Hybrids represent just 2.5% of new U.S. car sales, or less than 1% of the total U.S. pas-

senger fleet, according to the U.S. Department of Energy, but the market is expanding: Of the 32 hybrid models available in the U.S., 18 (56%) were introduced in the last three years.

PHEVs can be thought of as a compromise between pure electric vehicles and traditional combustion vehicles. They use electricity for initial travel (typically 30 to 40 miles) but switch to a gasoline engine once the battery is depleted. PHEVs thus deliver longer driving distances than pure battery-powered cars, but still achieve fuel savings relative to conventional and hybrid options; Chevy's Volt delivers a combined fuel efficiency of 65 mpg. A key downside for PHEVs is that drivers must both fill up at the pump and charge up their batteries, though at overall lower fuel costs than a conventional car. At the same time, the PHEV eliminates range anxiety and lets drivers travel as far as they like using gas, making it the more flexible vehicle given that most parts of the country lack public charging stations.

The Volt, named the North American Car of the Year this year, is

Alternative Vehicle Overview

How it works	Availability	Estimated fuel efficiency	Pros	Cons
Hybrid electric vehicle				
Uses an internal combustion engine as primary fuel source, but its battery stores energy from braking. Battery supplies a secondary source of propulsion, greatly improving fuel efficiency. Does not use electricity.	Has been available for more than a decade in the U.S. Represents approximately 2.5% of new car sales. About 32 models available now. Example: Toyota Prius.	Third-generation Prius is rated at 51 mpg in the city, 48 mpg on the highway.	Established track record. Modestly priced relative to electric options. Does not require charging station.	Consumers remain tied to gasoline prices. Fuel costs are high relative to that of PHEVs and BEVs. Larger carbon footprint than electric vehicles.
Plug-in hybrid electric vehicle (PHEV)				
Uses grid electricity for the first 30 to 40 miles. A conventional combustion engine extends car's range to around 350 miles. In contrast to a hybrid, battery is charged by electricity—thus "plug-in."	Limited availability in 2011 but additional options expected in 2012. Example: Chevy Volt.	Chevy Volt is rated at 65 mpg (composite based on 93 mpg electric, 37 mpg gas).	More flexible than a BEV because it can travel longer distances without charging. Can operate on gasoline after battery is exhausted, implying less dependence on public charging stations. A household outlet (120 volts) is sufficient to charge.	Expensive to purchase. Consumers remain tied to volatile gas prices. Substantial price premium relative to a hybrid for similar fuel efficiency. Driver must dual fuel (i.e., both fill up at the pump and charge battery). Requires an overnight charge.
Battery electric vehicle (BEV)				
Electric car that runs solely on battery power charged with grid electricity. Has no internal combustion engine.	Limited availability in 2011, but additional options expected in 2012. Example: Nissan Leaf.	Nissan Leaf is rated at 99 mpg equivalent (106 mpg city, 92 mpg highway).	Lowest fuel cost and carbon footprint. Does not require dual fueling. Owner eliminates exposure to high gas prices.	Expensive to purchase. Precedes availability of public charging stations. Battery life may be an issue. Typically requires 220-volt charging.

in limited production and has a 2011 manufacturer's suggested retail price (MSRP) of \$40,280. Chevy initially targeted producing 10,000 to 25,000 Volts in 2011 and has offered the car in only eight U.S. markets. But it has announced a ramp-up in production that will result in Volts being available in every U.S. dealership by the end of this year. Although firm numbers are hard to come by given the proprietary nature of this information, Bloomberg reported earlier in 2011 that Chevy planned to increase production in 2012 to 120,000 units. Chevy is reported to have sold around 2,184 Volts in the U.S. as of May.

BEVs are powered purely with electricity from the grid and can travel 60 to 100 miles before requiring a charge. (Actual mileage depends on factors such as battery size, weather, speed, and terrain). Because BEVs have a limited range, they are often derided as a niche product appealing only to tech-savvy urban commuters. But in fact, the BEV range now coincides with the driving habits of many Americans. Studies show that 70% of average daily driving is 40 miles or less, and that the average number of miles driven per day in major U.S. metropolitan areas is remarkably stable, typically less than 33. BEVs are unambiguously more efficient thanks to their use of electricity, with the Leaf, for example, achieving an estimated 99 effective mpg. So in theory, many conventional vehicles, hybrids, and even PHEVs could eventually give way to BEVs. Still, a lack of charging station infrastructure and inflexibility to manage longer trips without a charge are key obstacles that could give a competitive edge to hybrids and PHEVs for the foreseeable future.

The Leaf, named both European and World Car of the Year in 2011, closed its U.S. waiting list of 20,000 in September 2010 and is priced at \$32,720 (MSRP). Nissan expected to produce in the neighborhood of 4,000 Leafs per month in 2011, but reported that production stalled in the spring due

to the Japanese earthquake that struck on March 11. Nissan reported selling 2,167 Leafs in 2011 to date, and predicts that 2011 sales will be in the range of 10,000 to 12,000.

Economic Pros And Cons

The value proposition of alternative vehicles lies in their lower fuel costs, which are one-fifth to one-half those for a conventional car. This holds true for a range of gasoline and electricity prices, and is the result of an electric motor's ability to convert 90% of the energy content of electricity into mechanical energy, as opposed to an internal combustion motor's efficiency rating of 25%.

Assuming an average fuel efficiency of a U.S. passenger vehicle manufactured in 2010 of 22.5 mpg, chart 1 compares the per-mile fuel costs of a conventional vehicle versus those of a Toyota Prius across gas prices ranging from \$1 per gallon to \$7 per gallon. At a gasoline price of \$4 per gallon, for example, the per-mile fuel cost is nearly 18 cents for a conventional car but just 8 cents for a third-generation Toyota Prius, based on the EPA's fuel economy estimate of 50 mpg (*see chart 1*).

A BEV handily beats both alternatives, as shown in chart 2. A pure electric vehicle requires 0.25 to 0.35 kilowatt-hours (kWh) of electricity to travel a mile (or 25 to 35 kWh of electricity per 100 miles). The residential cost of electricity varies widely in the U.S. (ranging from 7 cents per kWh in North Dakota to 30.1 cents per kWh in Hawaii last year), with the average U.S. residential rate being 11.58 cents per kWh, according to the U.S. Energy Information Administration. (Residential rates are appropriate to use to calculate fuel costs for electric vehicles because until public charging stations proliferate, early adopters of electric vehicle owners will have to rely on charging their cars at home.)

The per-mile BEV fuel cost for a pure electric car yields a low of 2.4 cents, corresponding to the 7-cent-per-kWh rate in North Dakota, to a high of 10.2 cents, corresponding to the 30-cent-per-kWh rate in Hawaii. These

calculations are based on the Nissan Leaf, which can travel a mile using 0.34 kWh (see chart 2).

To compare rates across charts 1 and 2, and assuming a gasoline price of \$4 per gallon, the per-mile fuel cost of a BEV is 4 cents, assuming average U.S. electric rates. It's no surprise that "filling up" (i.e., fully charging) a Nissan Leaf costs about \$3.90. Transportation data suggests that the average U.S. driver travels 13,476 miles a year. Assuming \$4 gas, annual fuel savings from switching from a conventional car with average gas mileage to an electric vehicle is in the area of \$1,800 and could be more if the consumer pays less than the U.S. average for electricity (according to the Federal Highway Administration), suggesting that 10 years of fuel savings would roughly offset the higher sticker price on an undiscounted basis.

These estimates likely understate the fuel cost savings of PHEVs and BEVs at every electricity price point shown in chart 2 because most electric utilities are introducing special electricity rates for electric vehicle owners who charge their cars off peak. For example, Southern California Edison, which serves about half of California, charges residential customers about 16 cents per kWh—nearly 40% above the national residential average. But electric vehicle owners who install a separate meter to charge their car battery and charge their cars between 9 p.m. and noon pay 11 cents per kWh. And Georgia Power, whose rates average 10 cents per kWh, offers a "super off-peak rate" of just 1.25 cents per kWh to electric vehicle owners who charge from 11 p.m. to 7 a.m.

A key issue is whether the superior fuel costs of electric vehicles will be adequate to overcome today's high sticker cost. Even after the current \$7,500 tax credit, the MSRPs of the Volt (\$32,780 net of federal credit) and Leaf (\$24,220 net of federal credit) are above that of both a Prius (\$23,520, with no federal credit available) and a comparable conventional vehicle such as a Honda Civic, which achieves 28 mpg in the city

and 39 on the highway and has an MSRP of around \$15,000.

Economics Is Not The Only Consideration

There are other issues that could impede the adoption of electric vehicles besides cost and range anxiety.

Charging time

Electric vehicles charge far faster if owners install 220-volt home charging stations that cost \$1,500 to \$2,500, and that may be a necessity for some customers. The Volt, for example, can charge on standard 120-volt power (a conventional household outlet), but this requires 10 hours. With a higher voltage and a dedicated, but more expensive, charging system, a full charge takes less than four hours. Electric utilities or competing retail electric service providers could elect to fund the cost of basic charging equipment, or could establish a network of public charging stations, for which customers may be willing to pay a premium to use if charging times are faster than at home. Charging times can significantly increase in very hot and cold climates (i.e., above 95 degrees Fahrenheit or below 20 degrees).

Battery life

Batteries need to be replaced approximately every 10 years, and the need to replace such a sizable component of the overall vehicle cost is a factor in the customers' decision, as is the expectation that charging capacity could decline by as much as 30% as the battery ages. The lifetime of lithium-ion batteries is yet to be proven on a large scale, so manufacturers must provide battery life warranties that range from eight to 10 years. Although this reduces uncertainty for customers, it increases risks for auto manufacturers (although not materially, given the current low level of sales).

Safety

Consumers worry about safety issues resulting from lithium-ion battery use. Laptop batteries manufactured by Sony have exploded, causing small

fires and prompting large recalls of laptops by Dell, HP, Apple, Toshiba, and Lenovo in 2006. Lithium-ion car batteries weigh more than 400 pounds, and any explosion could be far more dangerous. Batteries used for electric cars are designed to be safe until they reach 250 degrees Celsius. Considering that gasoline is also highly flammable, this concern may be overstated. However, such issues may be factors until lithium-ion batteries have a longer track record on the road.

In The End, Electric Vehicles Are At The Beginning

A combination of environmental, fiscal, and national security considerations have brought the electric car into the spotlight for a national audition. Whether electric vehicles succeed in fits and starts or inspire a wave of enthusiasm that rivals that for existing hybrid vehicle technology is for now unknown. Although the signs point to a slow crawl forward, the concerns addressed (carbon, national security, and lower fuel costs for the gasoline-weary consumer) have arguably never been greater. These issues seem to have coalesced and created substantial momentum for auto manufacturers, which plan to launch an unprecedented number of alternative vehicles in the next few years. Battery technology trends also support improving economics, though federal and state subsidies will be required for several years until batteries can achieve parity with gasoline. Credit implications will be muted in the near term, but capital expenditures by utilities on grid upgrades and charging equipment could be material, as could the changes in operations and business mix that could be triggered as the technology spreads. **CW**

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Opportunity Knocks

The Policy Case For Electric Vehicles

Interest in electric vehicles arguably reached all-time highs earlier this year with the introduction of the Chevy Volt and the Nissan all-electric Leaf. The auto press quickly heaped accolades on the new models, with the Leaf being named World Car of the Year, and European Car of the Year while the Volt took the Northern American Car of the Year award and was Motor Trend's pick for best car of the year. Shortly after their debut, President Barack Obama announced a goal of putting 1 million cars on the road by 2015. And a February report issued by the Department of Energy estimated that leading auto manufacturers plan to ramp up production for the U.S. market to 1.2 million electric vehicles by 2015, ensuring enough supply to meet this goal and far surpass current production levels, with forecast 2011 production levels for the U.S. market at less than 50,000. (An estimated 10,000 to 25,000 Volts are expected to be available, and although the Leaf projected production of close to 48,000 in 2011, the Japanese earthquake has undercut this number.)

But as with any invention that is quickly dubbed the "next new thing," the fine print contains many catches that electric vehicles will need to overcome to become commonplace. Continued battery innovation will be necessary to drive down the costs of electric vehicles; private enterprise or government or some combination of the two will need to create a national charging infrastructure; and early adopters may need to see a sticker price for electric vehicles that is below the current price tag of \$33,000 to \$40,000.

These needs call for federal support in the general form of research and development funds to advance battery technology, sponsorship of private/public partnerships to jumpstart electric vehicle infrastructure investment, and direct rebates or subsidies for consumers considering an electric car purchase. To date



federal and state support for electric vehicles has been modest, with the most visible support for the new technology consisting of a \$7,500 tax rebate for consumers who buy an electric car, which the President has proposed be converted to a more attractive direct rebate at the dealership when customers buy an electric car.

While direct subsidies are the most obvious and often contentious of programs, the array of support that electric vehicles may need is much broader and includes measures both modest and monumental. We note that some of these are not financial and may be easier to implement in this strained fiscal climate. A sampling includes:

- Specifying tailpipe emissions limits that address carbon emissions, as California has done;
- Ensuring that state regulators work with utilities to offer a rational pricing structure that discounts the cost of electricity charging in off-peak periods;
- Establishing local permitting rules that ease the construction of charging stations and making sure that stan-

dards (such as plug adaptability) are universal across jurisdictions;

- Offering early adopters of electric vehicles access to commuter lanes, which may require bumping out high-occupancy conventional cars and offering other incentives such as lower car registration fees or access to superior parking spots in public lots (similar to handicap-restricted spots);
- Supporting complementary industries such as battery and parts manufacturing; and
- Most consequentially but also controversially, pricing carbon, which in the case of electric vehicles could just take the form of higher gasoline taxes without a complex wholesale cap and trade market.

Subsidy support is not new to the energy sector. The serious development of wind generation that began in 1999 and the current explosion of solar photovoltaics that began roughly in 2008 could arguably not have been achieved without hefty production tax credit and the invest-

ment tax credit, not to mention accelerated and bonus depreciation benefits that have shaved the cost of renewables, making them a more compelling choice. The solar industry has responded well to these incentives, in our view, with the cost of solar panels declining dramatically in the last two years. (See “Solar Panel Manufacturers Adapt To Commodity-Like Pricing And Fickle Demand,” published June 29, 2011, on *RatingsDirect on the Global Credit Portal*.) We expect electric vehicles to respond similarly and achieve lower costs due to economies of scale resulting from subsidies. These subsidies could then eventually be phased out.

But considering the staggering federal deficit, electric vehicles arguably face a treacherous road to getting greater policy support needed to jumpstart the technology. Whether this support ends up being substantial or immaterial is an important consideration in trying to predict the pace of adoption and thus the credit effects that electric vehicles could have for the electric utility sector, which will be tasked with providing fuel for a new fleet of vehicles.

While one defensible view is that federal support will stall amid our deficit woes, there are reasons that eventually electric vehicles will receive policy support. We expect this to occur because the policy case for electric vehicles has grown significantly. The U.S. is confronting problems that electrification of passenger vehicles can solve and that were not as marked in the mid-1990s, when the U.S. had its previous and extremely brief flirtation with electric vehicles.

We explore in this article the case for electric vehicles in a national policy context and why there are reasons to expect that electric vehicle technology will grow slowly but surely over the next several decades.

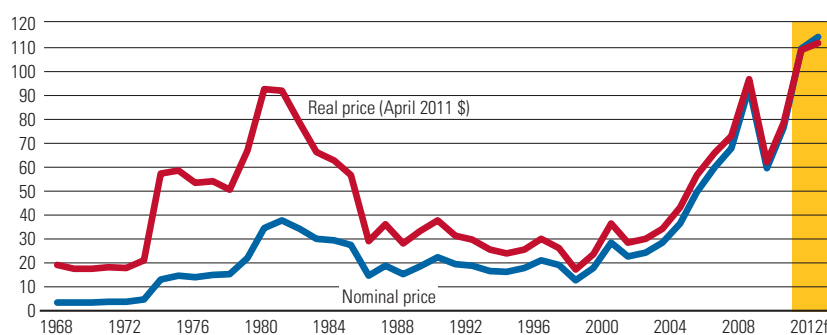
Foreign Oil Dependence And National Security Concerns

Using 19.1 million barrels per day, the U.S. was the world's largest petroleum consumer in 2010. Last year we imported about 49% of our petroleum requirements, which include crude oil that is refined into gasoline. According to the U.S. Energy Information Administration, about half of these imports came from the

Electric vehicles arguably face a treacherous road to getting greater policy support needed to jumpstart the technology.

Chart 1 Annual Imported Crude Oil Price

(Dollars per barrel)



f—Forecast.

Source: U.S. Energy Information Administration short-term energy outlook, April 2011.

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Western Hemisphere (34% from neighboring Canada and Mexico). Of the balance, 23% came from Africa and 18% from the Persian Gulf, leaving just 10% from other sources.

Although our dependence has declined in recent years, especially after the financial crisis in 2008, so has domestic production. Although our dependence on imports has varied, it has always been high. In fact, 2010 was the first year since 1997 that foreign oil dependence dropped to less than 50%. What is new is that geopolitical unrest is again underlying how much of our import supply is concentrated among a small number of nations, many of which are hostile to U.S. interests and which also often suffer from poverty and unstable regimes.

Because there is a single global market for oil, local disruptions are having a huge impact on oil prices borne by all consumers. This is underscored by the recent social and political turmoil in Libya, which is one of the top 20 oil producers and which holds about 4.4% of OPEC reserves. Global reliance on this supply, which seems relatively insignificant, has helped send oil prices to more than \$100 per barrel this year. Protecting our security interests in regions that we rely on for oil has increasingly become an expensive and dangerous proposition.

Fiscal, Trade, And Economic Concerns

The U.S.'s position as a big importer of oil has implications for our balance of trade. We spent more than \$900 billion, or 6.4% of GDP, on oil and petroleum products, and the U.S. trade deficit in crude oil and refined products in 2008 was \$388 billion, 56% of the total trade deficit. Based on 2008 numbers, these account deficits are a significant long-term concern, representing a substantial transfer of wealth that is linked to national security. And volatility in oil prices significantly affects industries such as airlines and constrains consumer spending, which accounts for about 70% of the U.S. economy.

As a result, even if the U.S. lessens the national security risks, there is little indication that the trade deficit will

narrow. Global demand for oil is increasing, in part due to the rapid economic expansion in countries such as China and India. Today, the number of cars on the road globally may be as high as 1 billion, and that figure could double in the next 20 to 25 years. As global demand rises, so does the prospect that the long-term price of oil could move higher, causing higher prices at the pump for Americans.

Following a long period of declining real and nominal prices, crude oil prices rose sharply over the last decade, although they declined temporarily during the global financial crisis (*see chart 1*). Oil price spikes have historically resulted from relatively transitory supply shocks, but the current and expected increases may be more permanent because of rising global demand and the lack of corresponding growth in oil reserves. For this reason most forecasters, including the Energy Information Administration (EIA), are predicting sharply higher oil prices in the next several years (*see chart 1*), and this translates into high predictions for gas prices. In its June 2011 short-term energy outlook, the EIA forecast that the annual average regular-grade gasoline retail price will increase from \$2.78 per gallon in 2010 to \$3.60 per gallon in 2011 and to \$3.67 per gallon in 2012. The sizable jump in retail prices predominantly reflects the higher average cost of crude oil.

Where Do Electric Cars Fit In?

The transport sector consumes the vast majority of U.S. oil, with passenger cars and light trucks accounting for about 46% of total consumption. Because the U.S. produces virtually all of its electricity from fuels (coal, nuclear, natural gas, and renewable generation such as wind and solar) that are mainly produced domestically, the opportunity to electrify cars is fundamentally one of swapping an imported fuel source for a domestically produced one. Estimates are that if electricity fueled 75% of the U.S. light vehicle miles traveled, U.S. oil import requirements would decrease to near zero. That means that if the U.S.

could electrify 100 million cars (or about 40% of those on the road today), it could displace all imports from the Middle East, according to NRG Energy.

Environmental Considerations Favor The Electric Car

Although federal carbon legislation clearly has given way to the political realities of a nation struggling to recover from a deep recession, efforts to

reduce carbon emissions continue in several states, particularly California.

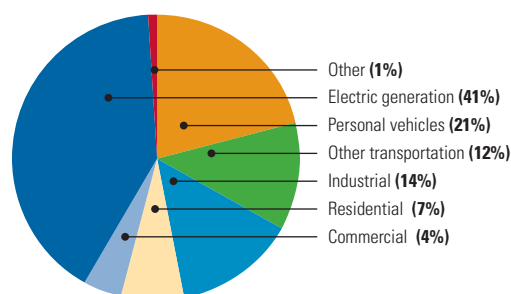
And although climate change is not a priority of the U.S. Congress, the Environmental Protection Agency (EPA) continues to push carbon regulation forward. In short, what to do about carbon is a question unlikely to fade away. And because passenger cars are a key culprit (the transportation sector as a whole accounts for as much carbon emissions as the power sector), any serious programs addressing carbon reductions will have to make meaningful changes to the mix of the U.S. passenger fleet. As chart 2 shows, passenger vehicles alone accounted for 21% of total U.S. carbon emissions in 2009.

California offers a glimpse of the role that electric vehicles could play as a policy tool. The state's cap and trade market, scheduled to begin in 2012 (but currently tied up in a legal challenge), will regulate auto tailpipe emissions at the refiner level, beginning in 2015. This will almost surely raise gasoline prices at the pump, assuming refiners can pass along all or a portion of the rising costs to consumers. But U.S. drivers are unlikely to reduce their consumption significantly in response to higher prices at the pump—certainly not to the levels required under the state's greenhouse gas laws (referred to as Assembly Bill 32). For this reason, key to obtaining greater reductions from transportation will be higher fuel economy standards (which have their limitations), greater reliance on biofuels (which produce modest, if any, reductions in carbon and which have global repercussions for food prices), and electric cars.

The staff of the California Air Resources Board, which is tasked with implementing cap and trade and other carbon emission programs, recently announced it would modify regulation for zero- and low-emission vehicles because they are key in meeting California's long-term air quality and greenhouse gas emission reduction goals.

The changes are part of a broader effort to strengthen California's low-emission vehicle (LEV) regulations. The proposed amendments, referred to as

Chart 2 **U.S. Greenhouse Gas Emissions Sources, 2009**

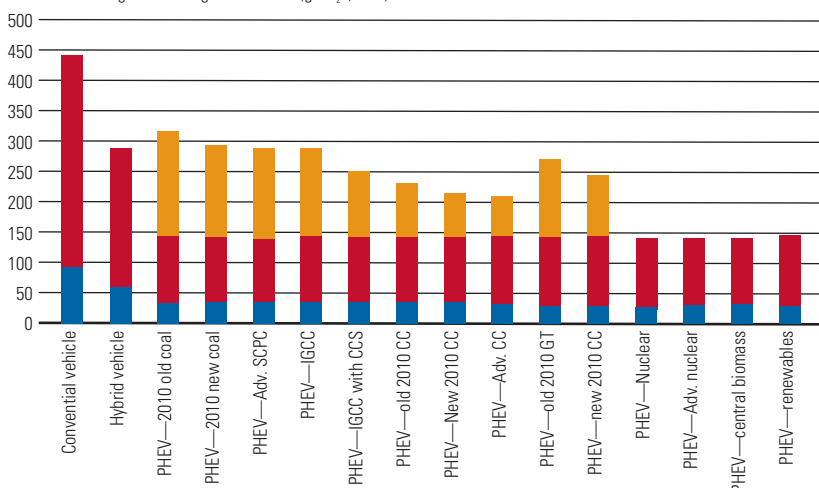


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Chart 3 **Estimated Carbon Emissions For Commercial, Hybrid, And Plug-In Vehicles***

■ Gasoline well-to-tank ■ Gasoline tank-to-wheels ■ Electricity well-to-wheels

Well-to-wheels greenhouse gas emissions (g CO₂e/mile)



PHEV—Plug-in hybrid electric vehicles. IGCC—Integrated gasification combined cycle. CC—Combined-cycle gas turbine. GT—Simple-cycle gas turbine. *Year 2010 comparison of PHEV 20 GHG emissions when charged entirely with electricity from specific power plant technologies (12,000 miles driven per year).

Source: Electric Power Research Institute.

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LEV III, ask for more stringent tailpipe and greenhouse gas emission standards for new passenger vehicles. Efforts to encourage plug-in hybrids and zero-emission vehicles will be rolled into any LEV III standards ultimately passed. Proposed new standards should be announced by fall 2011. Draft regulations focus on incubating alternative car technologies at levels that would allow for large-scale market penetration. On a smaller scale, the state has also been incenting alternative vehicle purchases by offering a clean-vehicle rebate of \$1,500 to \$5,000 for California residents who purchase an electric or hybrid vehicle. With an initial allocation of \$11.1 million for 2009 through 2011, the state's program proved popular, with funds depleted as of June 20, 2011. It is unclear if the current budget, inked recently, allocated additional funding to the program.

Even Coal-Derived Electricity Is Cleaner Than Standard Emissions

Because about 50% of U.S. electricity comes from coal-fired power plants, it may seem to be a paradox that electrifying cars provides a cleaner alternative to gasoline, given that gasoline is much cleaner than coal. But in fact, even if vehicles run on electricity using the existing U.S. generation base, greenhouse gas output would decrease. That's because the electric motor is far more efficient than the internal combustion engine.

A 2007 study by the Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC) showed that even if an electric vehicle is fueled entirely by older coal plants, its carbon emissions would be more than half those of gasoline-powered cars. And when considering cleaner sources of electricity, the difference only widens (*see chart 3*).

Note: 2010 comparison of PHEV 20 GHG emissions when charged entirely with electricity from specific power plant technologies (12,000 miles driven per year). g—Grams. CO₂ equivalent. Well to wheels—Emissions produced by

extracting, refining, and delivering gasoline to a customer. Tank to wheels—Emissions produced by the vehicle itself. Well to wheels—Emissions alternatively produced by generating electricity that is used to fuel a plug-in vehicle. Sources: the Electric Power Research Institute and the Natural Resources Defense Council, 2007.

Pure electric vehicles, such as the new Nissan Leaf, would produce emissions only from electricity. And if the electricity produced to fuel them is renewable, they would produce no emissions.

Vehicle electrification presents enormous opportunities for wind generation in particular. Although wind power has expanded throughout the U.S. over the last decade, its major drawback is that its production generally peaks at night, when electricity is least needed and when existing power plants are at low capacity utilization. Electric vehicles could sop up a lot of wind generation because electric cars would likely do the majority of their charging overnight. The relationship between vehicle electrification and wind generation could allow existing wind farms to be used more efficiently.

Car electrification will certainly increase electricity sales. But assuming that the bulk of charging occurs overnight, the increase in sales may not necessarily require the building of new power plants because excess capacity at night can be used to charge electric car loads. Given the amount of surplus power generation capacity that exists to meet peak air-conditioning loads during the day, the incremental capacity demands of electric vehicles may be modest, especially if power companies encourage car owners through off-peak discounts to charge at night. **CW**

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Credit FAQ

Renewable Energy In The Gulf

The Shams 1 Solar Power Project Financing

The signing of the Shams 1 solar power project financing in the United Arab Emirates (UAE) earlier this month has opened the way for a burgeoning in renewable energy in the Gulf, in Standard & Poor's Ratings Services view.

Three companies, France's Total S.A., Spain's Abengoa S.A., and Abu Dhabi-based Masdar gained a US\$600 million bank loan to build the plant, named Shams 1, which will have a 100-megawatt capacity and would qualify for carbon credits under the United Nation's Clean Development Mechanism (CDM).



We believe this marks the start of a potential new industry in renewables in the Gulf Cooperation Council (GCC) region, where renewables currently only represent less than 1% of the total energy mix.

In the following series of questions and answers, Standard & Poor's credit analyst Karim Nassif discusses why we think renewable energy will grow and takes a look at credit quality considerations.

Q. What is Standard & Poor's opinion on prospects for future renewable energy projects in the Gulf?

A. We have a positive view on the potential pipeline. The recently-closed Shams 1 deal establishes a precedent for renewable energy transactions and shows that such projects can be financed. However, the renewable energy sector remains in its early stages in the Gulf. According to the International Energy Agency, renewable energy projects represent only about 0.3% of the overall energy mix in GCC countries (GCC; Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and UAE; see table 1) to date.

Q. Why are renewable energy projects likely to gain momentum in the Gulf?

A. We see various explanations behind a pick-up:

- Renewable energy enables diversification away from oil and gas. It also allows the full economic potential of oil and gas reserves to be realized either through exports or through use in generating value-added products for foreign markets. We understand that the GCC countries intend to preserve oil and gas reserves for export purposes so as to safeguard their supply. Most countries in the GCC, with the notable exception of Qatar, are facing a gas supply-demand imbalance that, according to various estimates, could lead to a gas shortage of about 31 billion cubic meters (bcm) in 2015, compared to a shortage of about 19 bcm in 2009. What's more, conventional oil and gas fired power plants have proven costly as a result of fuel subsidies. These have ranged from around 2% to 12% of national GDP across GCC countries.

- We see a significant need to expand power production to meet domestic demand within the GCC and renewable energy represents a meaningful alternative to the traditional reliance on oil and gas. The region faces the twin challenges of

Table 1 Gulf Cooperation Council Sovereign Credit Ratings*

	Foreign currency	Local currency
Abu Dhabi (Emirate of)	AA/Stable/A-1+	AA/Stable/A-1+
Bahrain (Kingdom of)	BBB/Watch Neg/A-3	BBB/Watch Neg/A-3
Kuwait (State of)	AA-/Stable/A-1+	AA-/Stable/A-1+
Oman (Sultanate of)	A/Watch Neg/A-1	A/Watch Neg/A-1
Qatar (State of)	AA/Stable/A-1+	AA/Stable/A-1+
Ras Al Khaimah (Emirate of)†	A/Stable/A-1	A/Stable/A-1
Saudi Arabia (Kingdom of)	AA-/Stable/A-1+	AA-/Stable/A-1+

*Ratings on March 29, 2011. †One of the United Arab Emirates.
Source: Standard & Poor's.

Table 2 Solar Energy Resources In GCC Countries

Direct normal solar radiation		
	Direct normal radiation kWh/square meter	Direct normal solar irradiance kWh/square meter
Saudi Arabia (Kingdom of)	6.5	2,500
Qatar (State of)	5.6	2,000
Kuwait (State of)	6.5	2,100
Oman (Sultanate of)	6.2	2,200
Bahrain (Kingdom of)	6.5	2,050
United Arab Emirates	6.5	2,100

GCC—Gulf Cooperation Council. kWh—Kilowatt-hour.
Sources: American Institute of Physics: *Journal of Renewable and Sustainable Energy*, April 2009. A report on renewable energy research: A Critical Investment for the Arab Region, June 2007.

Table 3 Rates Of Energy Consumption And Carbon Dioxide Emissions In Qatar And The EU-27

Selected indicators	Qatar	EU-27
Average electricity consumption per capita (kWh)	17,573.0	6,388.0
Average carbon dioxide (CO2) emissions (million mt CO2 from fuel combustion)	48.5	3.9
Average CO2 emissions per capita (mt CO2)	58.0	7.9
CO2/GDP(kg CO2/\$)*	1.5	0.4

*At 2000 prices. mt—Million tonnes. kWh—Kilowatt-hour.
Sources: International Energy Agency (2007), World Bank.

building more power capacity for growing populations while supporting increased infrastructure development. We expect the GCC to invest about US\$100 billion over the next 10 years to increase power capacity. Meanwhile, we understand that the UAE, Qatar, and Saudi Arabia plan to spend some US\$170 billion on the transport sector alone in the coming 15 years. In addition, many countries are seeking to reduce their dependence on gas, including the UAE and Qatar, where most power plants are gas-fueled.

- Several GCC governments have announced renewable energy targets (often including nuclear power). For example, Abu Dhabi has announced that it aims for renewables to represent 7% of its energy production by 2020. Saudi Arabia, Kuwait, and Bahrain have also announced similar targets, both in terms of proportion and timeframe.
- Solar radiation levels in the Gulf are likely to support the operation of a rising number of solar projects (see table 2).
- We foresee a potential change in the energy mix worldwide following the troubles of Japan's Fukushima nuclear power plant after the March 11 earthquake and ensuing tsunami. It is currently too early to speculate on what the impact of the Fukushima nuclear incident will be for the renewable market globally. That said, any absence of nuclear power from the world's energy mix could lead to a greater dependence on conventional fuels for base-load demand (meaning the minimum amount of power that a utility or distribution company must make available to its customers, or the amount of power required to meet minimum demands based on reasonable expectations of customer requirements) and also on renewables. This may push GCC gas exports even higher, which could boost demand for renewable energy production within the GCC.

Q. *What are the main challenges ahead for renewable energy projects in the GCC?*

A. As with renewable projects everywhere, the absence of “supportive regulatory regimes” in the various GCC jurisdictions is a significant obstacle to determining the economics of projects. The Gulf region has not introduced a feed in tariff (FIT), investment tax credits (ITC), or renewable portfolio standards—all effective subsidies to facilitate the development of renewable energy projects. Carbon production also carries a limited cost (see table 3). Lastly, subsidized fuel prices in the Gulf put renewable projects—be it wind or solar among others—at an economic disadvantage compared with fossil fuel-driven plants.

The abundance of gas reserves in parts of the region, especially in Qatar, and the still-large oil reserves in the hydrocarbon exporting nations of the GCC, has led to slower development of renewable energy in the region than elsewhere. We think this could change, however, given that at least half of the GCC members have recently become gas importers.

Q. *What does the Shams 1 transaction mean for future solar projects in the GCC?*

A. The Shams 1 solar plant is the GCC's biggest renewable energy project to date and, in our view, could pave the way for similar projects in the future. The Shams 1 plant is being built under the independent water power and power producer (IWPP) model that Abu Dhabi already uses for conventional power and water desalination. We believe that other GCC countries may emulate Shams 1 if it proves to be an operational and financial success, particularly given the way that the IWPP model has spread across GCC countries in recent years. GCC countries' targets to generate 7% to 15% of power through renewable energy within the next 10 to 20 years offer another incentive for expansion.

Shams 1 has attracted a 22-year, US\$600 million bank loan from eight foreign and two local banks led by French bank BNP Paribas. The Shams consortium also received a US\$153 million equity subscription from its sponsors: UAE-based Masdar holds a 60% stake, alongside France's Total and Spain's Abengoa each holding 20%.

Two different processes generate solar power: solar photovoltaic (PV) cells that absorb light and concentrating solar thermal (CST) technologies that harness heat.

The Shams 1 project uses parabolic trough technology, which is a form of CST technology that generates electricity. Specifically developed by Abengoa, the technology includes mirrors lining rows of sun-tracking parabolic troughs. The mirrors concentrate sunlight on a central boiler to generate high pressure steam. The steam then drives turbines to generate electricity.

Under the model, we understand the project company will sell power to state utility Abu Dhabi Water and Electricity Co. (ADWEC) under a power purchase agreement. An important feature of the Shams 1 solar project is the introduction of a “green payment” under which the Abu Dhabi Ministry of Finance will compensate ADWEC for the difference between average domestic power generation cost and the generation cost for Shams 1.

In our opinion, the IWPP model could be replicated relatively easily in renewable energy project financing. What's more, the addition of the green payment addresses an aspect that we consider critical: providing political support in the form of this payment, which enhances the long-term viability of renewable transactions.

Q. *What is Standard & Poor's methodology for rating renewable energy projects and how does the methodology factor in features specific to the Gulf region?*

A. We apply our project finance methodology to assess the credit risks of renewable projects (see “Updated

Project Finance Summary Debt Rating Criteria,” published Sept. 18, 2007 on RatingsDirect on the Global Credit Portal). In accordance with our criteria, we evaluate general project-level risks, including contractual foundation, competitive market exposure, counterparty risk, and financial performance. We also assess project-specific risks, namely resources, technology, engineering and construction, and operations.

We have also published criteria specific to solar thermal and solar PV projects that elucidate the application of general project finance criteria to these projects (see “Key Credit Factors: Methodology And Assumptions On Risks For Utility-Scale Solar Photovoltaic Projects” and “Key Credit Factors: Methodology And Assumptions On Risks For Concentrating Solar Thermal Power Projects,” both published Oct. 27, 2009).

We don’t expect resources for solar projects in the GCC to present a significant risk given the highly predictable weather patterns in the region. However, we would expect to consider closely in our credit analysis aspects such as the stability, transparency, and predictability of regulation. We would also monitor operational and maintenance costs, given the potential for challenges encountered with desert dust, for example.

As for most Gulf projects, we would look closely at the ability to enforce any security provided to investors, and how the contractual structure of a transaction addresses this issue.

Q. *What factors support investment-grade ratings on renewable projects in the Gulf?*

A. When we evaluate any renewable energy project, we consider it critical to calculate estimated performance ratios for both solar and wind projects. Most solar PV projects that we consider as well designed and well built, for example, can in our view achieve performance ratios around 76% to 84% (see “Key Credit Factors: Methodology And Assumptions On Risks For Utility-Scale Solar Photovoltaic Projects”) in the first year

of operation. We assess the level of reserving, or the cash cushion, in a transaction to see if it can withstand periods of significant stress—for instance when volumes of solar radiation or wind fall—and still maintain robust debt service coverage ratios (DSCRs). Standard & Poor’s typically anticipates average DSCRs of between 1.4x and 1.5x minimum over the term of the debt (assuming fully amortizing debt) under its base-case scenario when rating a transaction. The DSCR could be lower, however, for well-structured PV projects using proven technology because the lack of moving parts in a solar PV project reduces operational risks. Also, PV projects have lower construction risks than any other type of power projects.

It is important to note that Standard & Poor’s does not publish specific ratio guidance for investment-grade projects because a range of qualitative factors contribute to its analysis of these projects.

Q. *What renewable energy projects does Standard & Poor’s rate?*

A. We rate one solar thermal project, U.S.-based Harper Lake Solar Funding Corp. We have also conducted credit assessments on a variety of European and U.S. solar projects. In addition, we rate a number of wind projects in Europe and the U.S., including FPL Energy American Wind LLC, Max Two Ltd., and Alte Liebe 1 Ltd. **CW**

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