Outlook for Renewable Energy in the Natural Gas-Rich North American Market

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Report prepared for Suncor Energy Inc.

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Executive summary

The last decade has witnessed a major boom in the renewables industry. Strong policies supporting renewable energy have led to more than US$200 billion of investment in renewable power capacity in North America since 2000. Wind and solar electricity capacity has grown from 4 GW in 2000 to over 75 GW at year-end 2012. North American ethanol and biodiesel usage averaged a combined nearly 15 billion gallons in 2012, up from less than 2 billion in 2000.

In just five years, however, the revolution in unconventional energy has transformed the North American energy sector. As concerns about growing oil and natural gas imports have been replaced by rising domestic oil production and debate over natural gas exports, the expectations and concerns driving North American energy policy and energy markets have shifted dramatically.

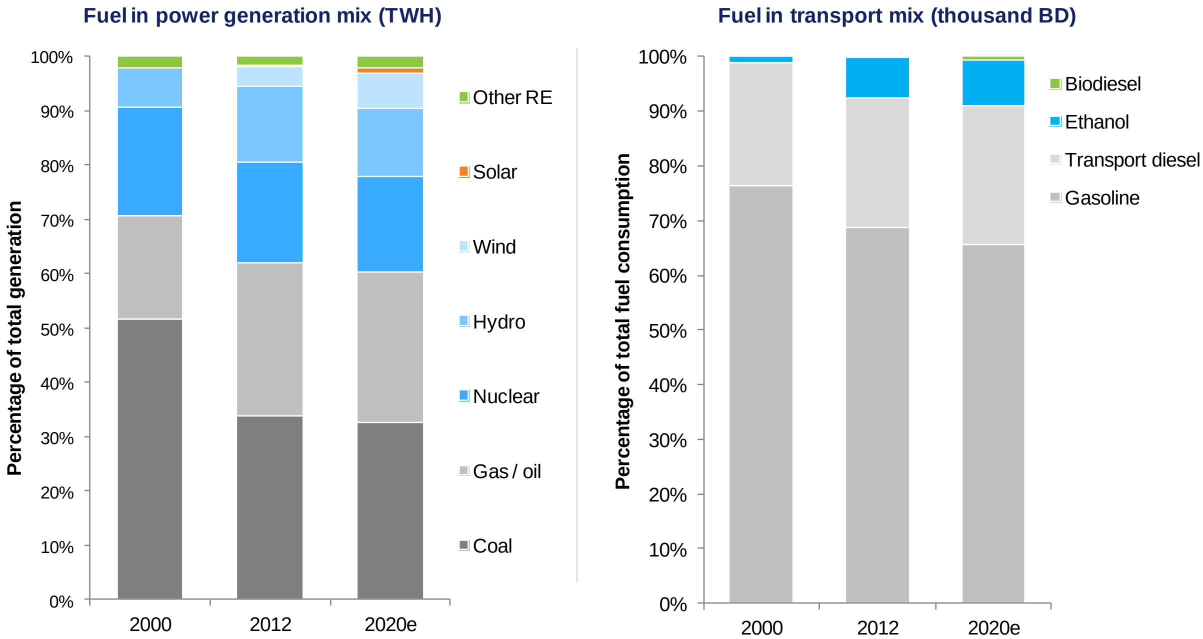
The revolution in unconventional energy, particularly the rise of shale gas, has meant that policy support will continue to remain crucial to the deployment of renewables across North America for at least the remainder of this decade. Enormous uncertainties face the Canadian renewables industry. The majority of the existing contracted wind and solar capacity, driven by provincial policies, is expected to have been completed by 2015, and few transparent drivers exist at this time to spur additional growth this decade. Future renewable RFP activity is uncertain and the recently finalized federal power sector CO_2 regulations are not expected to have much impact until after 2020, with new natural gas capacity expected to be best placed to accommodate decommissioned coal.

In the US, federal tax incentives for wind and solar remain in place for the near term and will continue to help bridge the gap between wind and solar costs and market prices for electricity. In the face of federal budgetary pressures, however, their extension beyond current timeframes at current price levels seems challenged. In the absence of federal tax incentives, existing state policies will serve as the most important driver of renewable energy growth in the US. State renewable portfolios standards (RPSs), which are usually set as gradually escalating percentages of retail electricity sales, exist in 36 US states. To date, US utilities have demonstrated a strong commitment to meeting the goals set by states: in aggregate, the industry is several years ahead of schedule in its procurement of renewable power. At year-end 2012, US utilities had acquired nearly 60% of the renewable power required to fulfill mandated obligations by 2020. The pace of early compliance, however, also means that the rate of capacity additions in the rest of the decade is bound to slow from the most recent previous years.

Against this backdrop, renewable energy's contribution to the North America energy mix is expected to grow gradually, paced largely by the ability of policies in place to support the industry. Wind and solar—the backbone of renewables growth recently—accounted for just 4% of North American power generation at year-end 2012, and are expected to reach over 7% of North American power supply by 2020. Biofuels already account for roughly 6% of road transport fuel (gasoline and diesel) in the US, and this is expected to reach 10% by the end of the decade. Canadian ethanol consumption is at about 5% of the gasoline market, and has headroom to increase further.

To achieve a broader place in the North America energy market, either a dramatic shift in the cost of renewable energy or much greater urgency to reduce CO_2 emissions will be required. Even stronger biofuels growth could occur if technological breakthroughs—elusive so far—were to occur, allowing development of advanced cellulosic fuels.

Exhibit 1: Renewable energy market share outlook in North America: 1990–2025



Source: IHS

Canadian policy status and outlook for renewable power

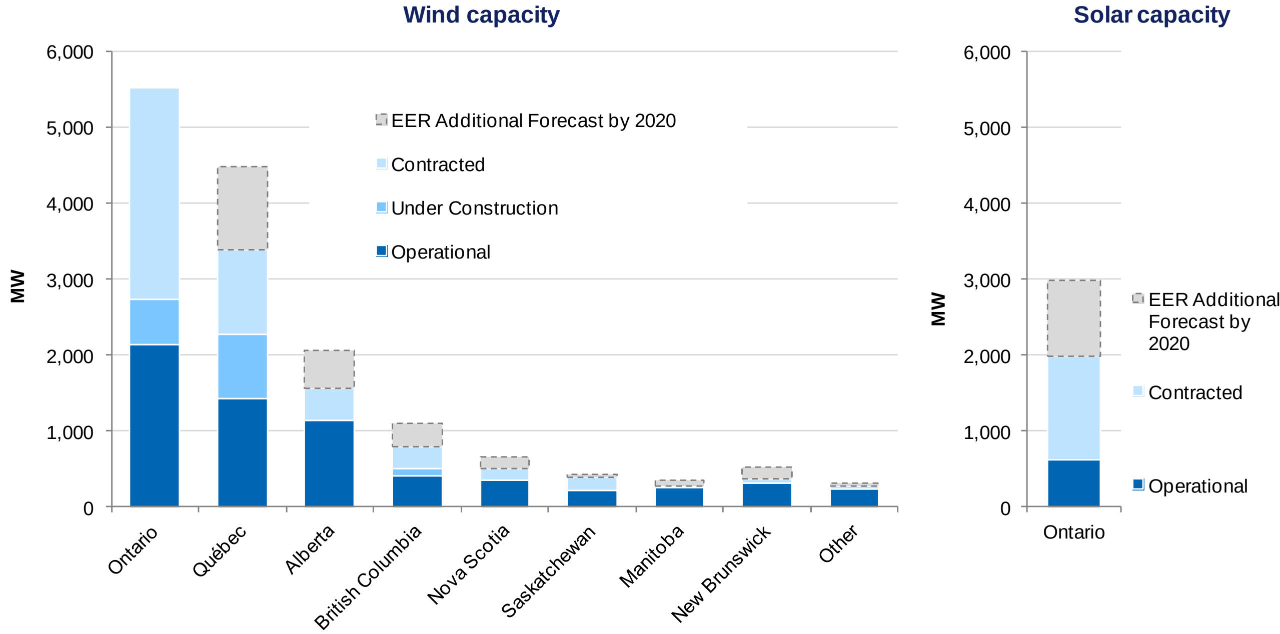
Canada's stance on global climate change has evolved in recent years. One of the first countries to sign onto the Kyoto Protocol (Kyoto) in 1998, Canada ratified the agreement in 2002, positioning itself as a leader in the global climate change debate. But the realities of the Great Recession and the rise of oil sands as a major contributor to economic growth changed the country's course. In 2011, Canada pulled out of the Kyoto Protocol.

Nevertheless, Canada continues its sector-by-sector regulatory path toward reducing its CO_2 emissions. Final regulations targeting CO_2 emissions from Canadian coal-fired power generators were issued in late 2012 and will go into effect on 1 July 2015. These regulations set the stage for a phase-out of Canadian coal-fired power generation. In its place is an evolving role for greater use of domestic shale gas resources and renewable energy, led by wind and solar as technological advances drive down the cost of these resources for power generation.

Canada is poised to account for over 20% of all of the wind and solar capacity added in North America from 2013–2015. Canada's installed wind base will nearly double from 2013–2015, increasing from 6 GW to over 10 GW, driven mainly by supportive policies enacted over the last decade in Quebec and Ontario. 1.7 GW of new solar PV is also expected to be added, virtually all in Ontario, by the end of 2015.

Provincial requests for proposals (RFPs) and feed-in tariffs (FITs) in Ontario are the main drivers behind wind and solar energy procurement, but much of the renewable capacity necessary to satisfy provincial goals has already been procured, and new policy proposals are threatened by the changing political environment.

Exhibit 2: Progress toward renewable energy targets by province in Canada



Note: Estimate for BC target based on 2,000 GWh of new renewable energy recommended by 2012 BC draft Integrated Resource Plan; wind projects are assumed to win the same proportion of future RFPs that they won in BC Hydro's last Clean Power Call (40%). Manitoba target of 1 GW, announced in 2006, not included due to omission from the province's 2010 power plan. Ontario includes 870 MW of contracted capacity under development by Pattern and Samsung. IHS does not expect all contracted wind capacity in Ontario will be completed by 2020
Source: Provincial energy plans, IHS

After a surge in new capacity additions in the next few years, the outlook for wind and solar growth in the second half of the decade in Canada faces significant uncertainty. New growth will be contingent upon the adoption of new provincial initiatives or a shift in federal energy policy. In Ontario, Canada's largest renewables market, momentum is shifting away from larger-scale renewables development towards smaller scale and distributed opportunities.

US federal and state policy status and outlook for renewable power

The revolution in unconventional energy is having a particularly significant impact on the renewable power sector in the US. Although cost reductions in renewable energy have made these technologies competitive with many forms of power generation, the boom in unconventional gas has eroded that benefit, leading to a continued need for subsidies. As a result, the timing and scale of renewables growth in the US, as in Canada, will depend in large part on policy evolution.

Over the next several years, US renewables policy will face a number of crossroads as current federal tax incentives are set to expire, while existing US state RPSs mandate nearly twice as much renewable energy in 2020 as is generated today. US federal tax incentives for wind and solar remain in place for the near term and will continue to help bridge the gap between wind and solar costs and market prices for electricity. In the face of federal budgetary pressures, however, their extension beyond current timeframes at current price levels seems challenged.

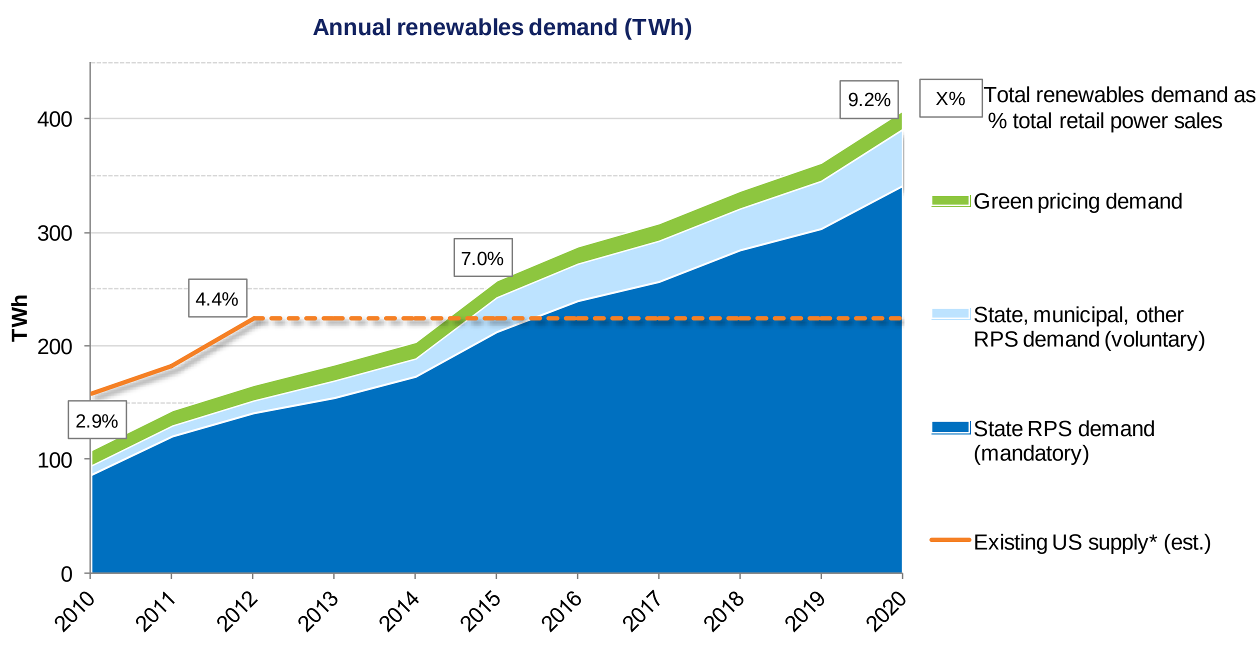
IHS expects that the combination of wind and solar will represent approximately 50% of the 126 GW of total new power capacity expected to be added through the end of the decade. The primary policy driver for renewables in the US remains state RPS policies, which are expected to be largely enforced and fulfilled. It is also expected that federal production tax incentives will remain in place through 2015 for wind, but then expire, while the Investment Tax Credit (ITC) for solar is also allowed to expire after 2016.

In the seven years since most RPS policies took effect, US utilities have demonstrated a strong commitment to meeting the goals set by the states: in aggregate, the industry is several years ahead of schedule in its procurement of renewable power. At year-end 2012, US utilities had acquired nearly 60% of the renewable power required to fulfill mandated obligations by 2020. The pace of compliance, however, also means that the rate of capacity additions in the rest of the decade is bound to slow from previous years. Most RPS states currently face an oversupply of renewable energy credits (RECs), a condition magnified by the ability to bank excess RECs for future use.

IHS EER estimates that utilities will need to procure an additional 140 TWh of new renewables by 2020 to meet the 340 TWh target required by binding RPS policies. Adding voluntary state goals and green pricing program brings the total estimated demand to roughly 400 TWh (see **Exhibit 3**). This additional mandated demand translates to between 50 and 60 GW of new wind and solar.

Although the repeal or reduction of RPS targets will remain a risk for renewables demand, the short history of these policies has largely been one of expansion rather than contraction. Bills have been proposed in many state legislatures to reduce or repeal RPS targets, but no states have yet enacted legislation doing so (the one exception is Virginia, which will likely remove the financial incentive from the state's voluntary RPS policy). It is expected that, on balance, state policy support for existing RPS policies will remain largely in place over the next decade.

Exhibit 3: Outlook for supply and demand for renewable power in the US



Source: IHS

While state RPS legislation has defined the level of renewable power demand, federal tax incentives will have significant impact on the timing of development that satisfies that demand. Federal tax incentives play a big role for both the wind and solar industries in the US. For wind, the production tax credit (PTC) is approximately US$23/MWh, and any project that begins construction by the end of

2013 is eligible. For solar, the investment tax credit (ITC) remains in place through the end of 2016 and is equal to 30% of a solar project's total capital cost.

Costs for wind and solar projects have been driven down significantly since 2008. This improvement has meant that wind will be competitive with the marginal costs of natural gas in several US markets when the production tax credit (PTC) is in place. Utility-scale solar is expected to remain at a cost disadvantage compared with marginal gas prices outside of the southwest through the remainder of this decade. As a result, its growth will remain largely driven by the opportunity to satisfy state RPS targets.

The last minute and difficult congressional negotiations to extend wind's tax credit at the end of 2012 underscore the long-term uncertainty over the tax credit's future. With the future of the PTC and ITC uncertain, the US renewables industry's attention has broadened to alternative financing structures. One such option under debate in the US Congress is to amend the tax code to allow Master Limited Partnerships (MLPs) to invest in renewable energy projects. MLPs are currently widely used for a variety of qualified sources including real estate, hydrocarbons, and certain other commodities, but are not currently eligible to invest in renewable energy.

The evolution of broader carbon policies in the US also has the potential to influence the energy mix of the future. While policy development pertaining to greenhouse gas (GHG) emissions has generally lagged behind more targeted renewable policy support in the US, there is evidence that political landscapes are evolving and several factors together could drive more legislative activity this decade.

While there are challenges to implementing strong federal legislation in the US, a growing awareness of the impacts of CO_2 emissions, an improving economy, and controversial regulatory action aimed at curbing stationary source carbon dioxide (CO_2) emissions under the US Clean Air Act (CAA) continue to form a backdrop that could result in a national carbon policy by the end of this decade in the US. Moreover, if additional extreme weather events occur it could provide a further political impetus to act.

A plausible outcome over the course of this decade in the US is continued rollout of EPA GHG regulations for stationary sources under the CAA, followed by passage of legislation that replaces these regulations with a national cap on CO_2 emissions from the power sector. It is very likely that any cap-and-trade legislation would include provisions to limit the resulting market-based price for CO_2, and thus temper its ability to have a very significant impact on the fuel mix for many years.

Cost dynamics for wind and solar development in North America

The competitive dynamic of the renewables market has changed significantly over the past couple of years as most major utilities have procured sufficient renewables to meet RPS obligations for the next three to five years. While procurement will continue, it will do so not only at a slower pace but also with more deliberation about price. Even as demand for procurement slows, the number of suppliers in the market—independent power producers looking to sell renewable power—has increased with the market's expansion. Pressure from both the demand and supply sides of the market are thus likely to squeeze returns on renewable projects, a condition expected to be sustained for the next several years as the competitive landscape seeks a more sustainable balance.

Institutional investors are also becoming more active in the North American M&A market, targeting contracted capacity for stable long-term yields. Pension funds, insurance companies, and traditional infrastructure funds represent an increasingly important source of capital for the industry. Financial buyers accounted for 26% of North American renewable asset transactions in 2012. The growing installed base of renewable power capacity offers more opportunities for these risk-averse investors.

Cost-competitiveness of wind

As the wind industry continues to mature, the cost of wind energy has declined considerably, driven by the push toward larger turbines at higher hub heights, yielding better efficiencies. Wind turbine prices peaked in mid-2008 as turbine shortages, sharp increases in commodity prices, and the appreciation of the euro applied upward pressure on pricing. Since this time, the North American wind turbine market has built substantial domestic manufacturing capacity while competition has increased and a glut of turbine supply has exceeded regional demand. This combination of factors has led turbine prices to drop by 25% to 30% since 2008.

With competition in the turbine market forecasted to remain intense, OEMs have become more competitive to differentiate themselves through product innovation, services, pricing, and quality track record. Most wind turbine manufacturers are focusing on a combination of technology and scale in their latest product offerings. Better wind turbine efficiency has in some cases led to the ability to increase annual energy production from a new wind farm by over 20%. North American developers are witnessing record capacity factors at new wind sites, with net capacity factors ranging from 50%-60% in some of the windiest regions. Despite cost improvements overall, wind will still struggle to be cost-competitive with wholesale power prices in nearly every region of North America without subsidies for the remainder of the decade.

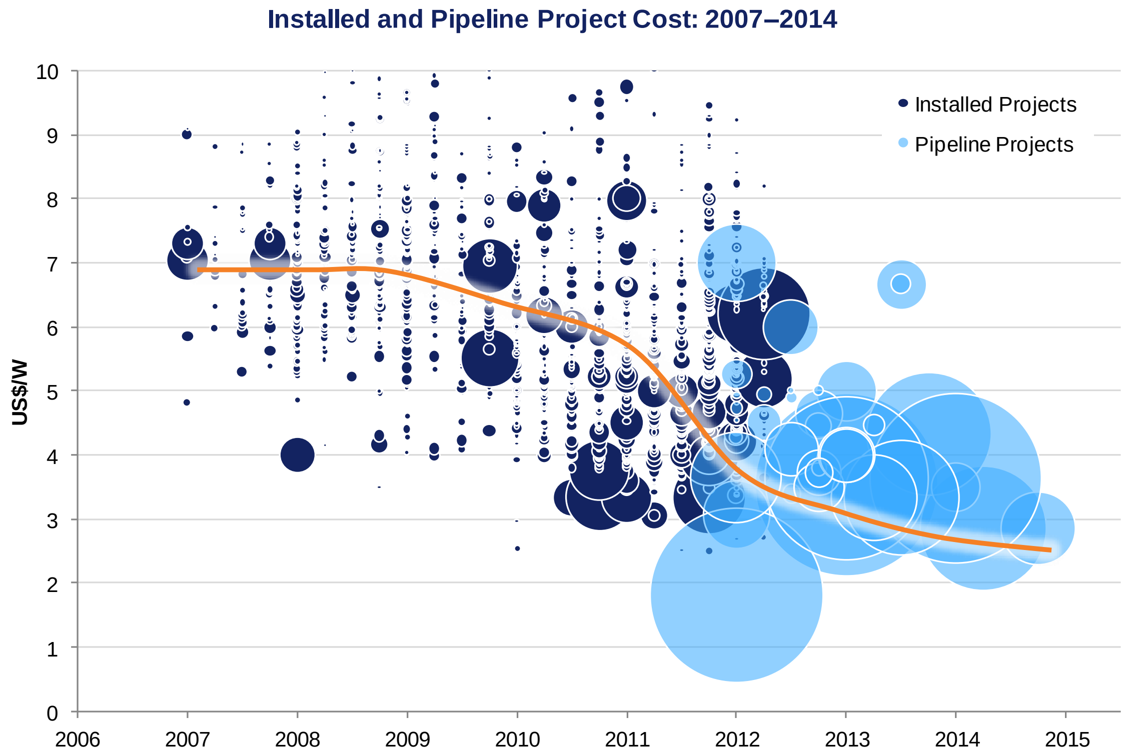
Solar demonstrates improving cost profile

In North America, solar PV project costs have also improved dramatically, having come down 30% since 2011. Costs are expected to fall further in 2013 and 2014, driven by modest declines in component prices as well as industry focus on cutting engineering, procurement, and construction (EPC) and development costs, owing to the prevalence of low-cost natural gas.

The cost outlook for different solar PV technologies is based on unique factors and input drivers. For crystalline silicon PV, key cost drivers are advances in cell doping technology along with the movement to thinner wafers to reduce material cost. PV modules are also becoming more efficient through better cell physics. Improvements in inverter efficiency also play a lesser role in driving overall cost gains.

For thin film PV, key drivers of cost declines include advances made in material deposition technology and the movement to less-expensive substrates. Also, better deposition process quality can improve solar cell uniformity, boosting solar farm efficiency. For both thin film and crystalline silicon, reduction in balance of plant costs, installation, and vertical integration all are anticipated to result in appreciable contributions to cost reductions moving forward.

Exhibit 4: Project capital cost trends by category



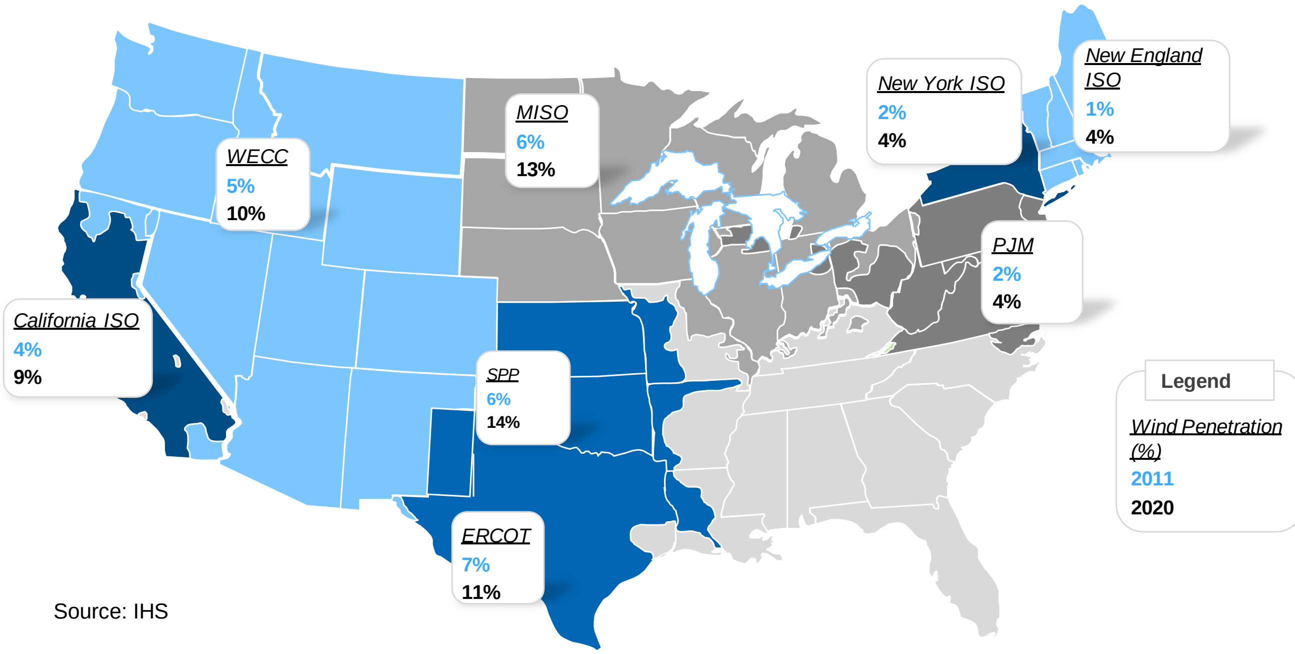
Note: Line illustrates the trend. Representative national average costs for a 20 MW ground-mounted project; EPC includes balance of system and installation costs
Source: CPUC, companies, IHS

Wind, solar integration: risks and opportunities

Integrating variable renewable power sources, primarily wind and solar, into utilities' energy mix presents multiple challenges. Renewable resources are frequently intermittent, requiring system-wide back-up. Renewable resources also tend to be disbursed far from load centers, requiring investment in new transmission to get renewable power to market.

Growing wind penetration across most major North American power markets is spurring market integration initiatives to maintain grid reliability while minimizing the cost of wind variability. As a result, rising wind penetration levels can be reliably accommodated in all North American power markets this decade. By 2020, IHS EER forecasts wind to surpass 10% penetration in at least four major North American regional grids—SPP, MISO, ERCOT, and WECC—with penetrations between 4% and 9% in most other regions outside of the US Southeast. At increased penetration levels, wind uncertainty, variability, and ramping behavior pose challenges to system operators and market efficiency.

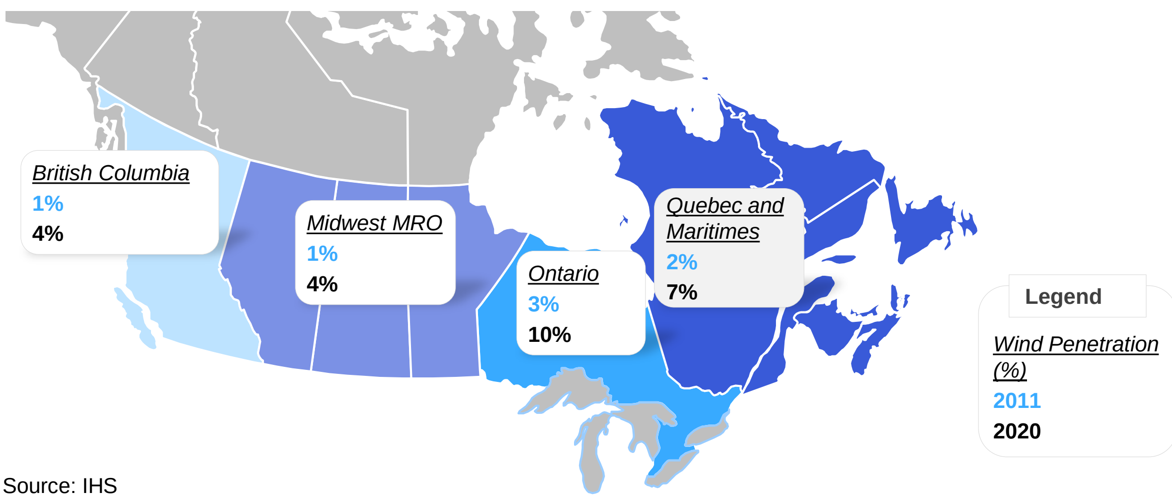
Exhibit 5: Current and forecast wind penetration in US ISO/RTO operating regions



Source: IHS

Wind penetration in Canada is expected to range from 4% to 10% across different provinces by 2020. Ontario will face the highest wind penetration levels, reaching 10% by end of the decade. Growing wind generation is already causing some grid challenges. Adding wind generation has altered the alignment of the integrated hydro, base-load, cycling, and peaking supply with net load. At times, Ontario's power system has faced over-generation when wind output adds to existing supply from hydroelectric generation, and together there is too much generation relative to Ontario's net load plus export capability. Hydro generation has limited flexibility owing to water flow requirements imposed by navigation, fish management, and irrigation needs. The result has been the need to curtail some wind generation.

Exhibit 6: Current and forecast wind penetration in Canadian grid regions



Source: IHS

Grid operators across North America are beginning to require greater wind participation in economic dispatch to increase market efficiency and to reduce the burdens on system operators from integrating wind. All balancing authorities have adopted centralized wind forecasts to better prepare for wind output in day-ahead unit commitment and real-time dispatch; the costs of implementing centralized forecasts are low compared with their estimated benefits to the system.

Biofuels markets and outlook

Government mandates have driven strong growth in biofuel consumption in both the United States and Canada. And, at least in the US, existing regulations obligate a continued steep ramp-up in biofuel usage. However, there are important technical obstacles to market growth at the pace implied by the US federal mandate. Obstacles to growth in the ethanol market include the current saturation of the US market with 10% ethanol blends (E10) and the unwillingness of auto manufacturers to warrantee vehicle engines for use of ethanol blends beyond the 10% level. For advanced biofuels, there are technical challenges to scaling commercial production capacity to what is needed to satisfy aggressive statutory requirements. Technological innovations have lagged, disappointing those who expected “cellulosic” and other advanced biofuels to now be widely commercially viable.

These obstacles suggest that North American biofuel growth will proceed at a slower pace over the next few years than in the past. Nevertheless, in the US, the tradable credits system overlaying the federal mandate should ultimately create enough incentive for some fuel retailers to begin supplying ethanol in excess of the current de-facto 10% limit, either in the form of up to 15% blends (E15) or greater availability of niche fuels such as up to 85% ethanol (E85). However, the availability of cellulosic fuels in the volumes required by the federal mandate are extremely unlikely given the lack of technological progress thus far, and this portion of the federal mandate will likely require a revamp by Congress.

Growth in Canadian demand for biofuels is likely to be more tied to refining economics. Although Canada is at the level required by its own federal mandate, it is not yet at the 10% level for ethanol reached in the US, and therefore there is still room for growth. With the price of ethanol below that of gasoline, refiners will tend to value ethanol as a gasoline volume “extender.” Refiners will also value ethanol for its high octane content. As long as corn remains at a price such that ethanol can be produced at a cost well below crude oil, market forces should drive increased ethanol blending in Canadian markets still below the 10% de-facto limit.

Room for further growth in Canadian biofuels market

Canadian biofuels mandates came into law recently. Canada’s federal mandate, the Renewable Fuels Regulations, has required 5% content ethanol in the gasoline pool since late 2010, with a requirement of 2% renewable content in the distillate fuel market (diesel and heating oil) since mid-2011. In addition, several provinces have their own requirements—some higher than the federal obligation.

Approximately 75% of the Canadian ethanol industry is corn-based, while 25% is wheat-based. Corn-based ethanol plants are typically more efficient than those using wheat, mostly because of the superior ethanol yields that corn affords. Therefore, in the hierarchy of the North American ethanol industry, wheat-based plants are generally the highest cost.

Canada’s biofuel challenges are somewhat different than the US. Although it does not have an escalating federal requirement like the US, its production base is small and Canada depends on imports (principally from the US) to comply. Canada imported about 20,000 bd of ethanol from the US in 2012, or about half its ethanol consumption; and 5,000 bd of biodiesel, or 70% of its biodiesel consumption. New capacity is coming online, but Canada is likely to remain a net importer of biofuels.

Canadian imports of US biofuels generally are the result of surplus capacity that exists in the US market.

In the US, in the years before the E10 blend wall was reached, refiners typically over-complied with their RFS obligations because ethanol was generally cheaper than gasoline. It therefore had considerable “extender” value for refiners when blended in conventional gasoline. Ethanol has also provided to have significant “blend” value depending on market conditions due to its high octane content. Ethanol’s price relative to petroleum gasoline and crude oil is a function primarily of corn prices. Despite the increase in corn prices over the past decade, in general, gasoline and crude prices have been high enough to allow ethanol to be produced at a cost below petroleum.

The recent drought pushed up corn prices significantly in 2012. However, if the drought recedes, corn prices are likely to continue falling or will remain at their recently weaker level. This should tend to result in a price differential between crude oil and ethanol that is sufficient to incentivize additional ethanol blending in places where the 10% level has not yet been reached, such as in Canada.

Growth in Canadian biodiesel consumption may be more challenging because biodiesel is generally significantly more expensive than petroleum-diesel. This is primarily a function of the lack of affordable feedstock. Vegetable oil (principally soy and canola oil in North America) is expensive relative to petroleum, and is principally produced for the food market. Large increases in demand for vegetable oil from the biodiesel industry would likely push its cost up even further.

Bio-based diesel is for the most part produced from the transesterification of vegetable or animal oils with simple alcohols to produce mono-alkyl esters, known as biodiesel. However, some bio-based diesel in North America is produced via an alternative process: hydrotreating of vegetable oils or animal fats in a conventional petroleum refinery. Bio-based diesel produced via this method is known as “hydrotreated renewable diesel” (HRD). This process produces a superior end-product that is a hydrocarbon “drop in” substitute for petroleum diesel. HRD represents a minority of the bio-based diesel produced in North America, but capacity is growing. One advantage of HRD is that it can process feedstocks like yellow or brown grease, that cannot typically be run through transestertification plants. These feedstocks are also cheaper than vegetable oil.

US renewable fuels standard and Canadian biofuels mandate

Government supply mandates remain the foundation for increased North American consumption of biofuels. The original US RFS program (RFS1) was established under the Energy Policy Act of 2005 (EPAct), which amended the Clean Air Act (CAA). The Energy Independence and Security Act of 2007 (EISA) required changes to the original RFS program, resulting in RFS2. The volume of biofuels mandated to be consumed under the RFS2 increased compared to RFS1, and the number of categories of biofuels that were required was further defined.

RFS2 requires specific volume standards for cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuel that must be used in transportation fuel each year. The required total renewable fuel volume rises to 36 billion gallons per year (2.35 million bd) by 2022.

Within the advanced biofuel category, there are two specific “carve-out” categories of required fuels: cellulosic biofuels and biomass-based diesel. The volume difference between the total of these two categories and the total “advanced” biofuel requirement can be fulfilled by supplying “undifferentiated” advanced biofuels, defined as any biofuel that has a 50% GHG lifecycle reduction. Brazilian sugarcane-based ethanol is eligible under this undifferentiated advanced biofuel category. Conventional biodiesel—which is deemed to have a 50% GHG lifecycle reduction relative to petroleum-based diesel—fulfills the requirements for the biomass-based diesel carve-out, and could also be used to fulfill the generic “advanced biofuel” requirement.

Refiners and fuel importers (known as “obligated parties” in the RFS program) show compliance by submitting credits to the EPA. These credits are known as “Renewable Identification Numbers”, or RINs. Each batch of biofuel produced is associated with a specific RIN; when obligated parties blend that particular batch into the fuel market, they take ownership of the RIN. The RIN can be submitted to the EPA as proof of physical blending, banked for future compliance, or traded in the marketplace to other obligated parties who are short physical gallons of biofuels. Each year, obligated parties are required to meet their pro-rated share of the RFS by submitting RINs to the EPA—RINs that are either collected through physical blending or purchased from other obligated parties. RINs have a value that fluctuates based on supply and demand, and are intended to act as a market incentive for obligated parties to meet the RFS’s targets.

The difficult path over the E10 blend wall in the US

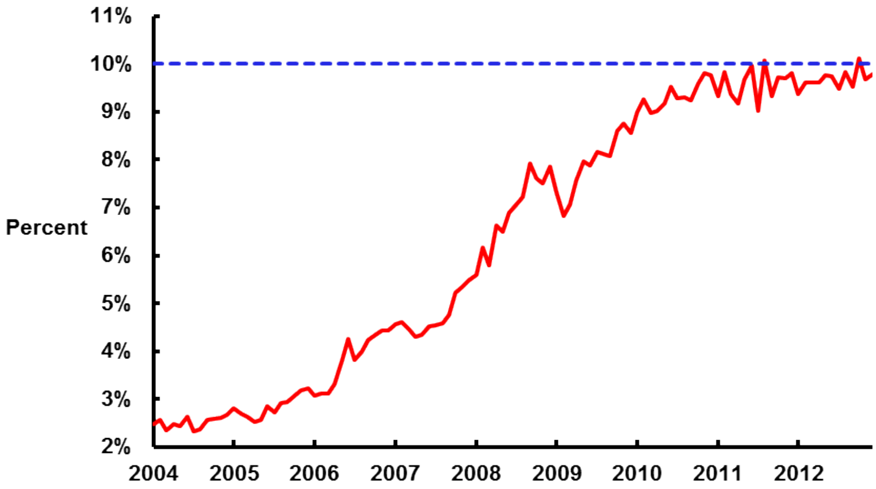
Biofuels such as ethanol and biodiesel are typically incorporated into gasoline or diesel in low-volume blends. Ethanol is most commonly blended with gasoline at 10% by volume. These blends are known as “E10”. The 10% limit exists because automakers have historically refused to provide engine warrantees to owners who use ethanol-gasoline blends above this level. If the majority of gallons sold remain E10, then the maximum level of ethanol that can be supplied in the gasoline pool is 10% of the total gasoline market. This is where the US market stands currently—the entire market has been almost completely saturated with E10 since late 2010 (see **Exhibit 6**).

When the RFS was devised by Congress, it was assumed that overall transportation fuel use—especially gasoline—would continue to rise. From 1997–2007 (when RFS2 was enacted), US gasoline demand grew from 8 million bd to almost 9.3 million bd, or 1.5% per year. Since then, however, gasoline demand has contracted, falling to 8.7 million bd. As the gasoline market shrinks, the maximum volume of ethanol that can be accommodated becomes increasingly limited.

Gasoline demand has declined owing to the weak economy (and subsequent high unemployment), improving fuel economy of the vehicle fleet, as well as changes in consumer behavior in response to rising prices over the past decade. Gasoline demand may show some modest increases over the next few years as the US economy continues its drawn-out recovery, but the long-term expectation is that demand will resume a steady decline owing to much stricter federal fuel economy regulations, which are in place through 2025.

In the meantime, the E10 blend wall is becoming a major hurdle for RFS compliance. In 2013, the RFS calls for 16 billion gallons of renewable fuel to be supplied, including about 1.3 billion gallons of biomass-based diesel. Ethanol—some combination of conventional corn-based ethanol and Brazilian sugarcane-based ethanol—is the only renewable fuel available in sufficient volumes to meet the remaining 14.7 billion gallons obligation. However, the gasoline market is only expected to be about 134 billion gallons (8.7 million bd) in 2013, assuming little to no growth relative to 2012. This implies that almost 11% ethanol by volume would have to be blended in gasoline to comply with the RFS.

Exhibit 7: Total US ethanol share of gasoline market by volume



Source: IHS

RIN values have jumped dramatically in 2013, as obligated parties have been unable to generate the necessary incremental RINs through increased physical blending because of the blend wall, and instead are drawing down stored RINs or going into the RIN marketplace to purchase credits from other obligated parties. The RIN price is a direct reflection of the E10 blend wall constraint.

A potential pathway to incorporating more ethanol into the transportation market is by supplying more ethanol through E85 (up to 85% ethanol, 15% petroleum-based gasoline). However, growth in the E85 market is constrained by the limited number of flex-fuel vehicles on the road—the only vehicles that can accommodate E85, as well as the need for retailers to supply the fuel through specialized pumps and tanks. At the end of 2011, only about 2,400 fueling stations nationwide sold E85. The number of FFVs in the US is estimated at approximately 10 million units, or about 4% of the vehicle fleet. E85 also has lower energy content per gallon than E10: the energy content and mileage efficiency (mpg) achieved of an 85% ethanol blend is about 25% lower than E10. Therefore, unless E85 is discounted sufficiently (to roughly 75% or lower than the price of E10), it may be less attractive to motorists. For these reasons, it is unlikely that obligated parties will pursue a strategy of dramatically expanding the existing E85 fueling network to comply with the RFS targets.

Increased blending of biodiesel is another potential strategy to get around the E10 blend wall. However, biodiesel generally has relatively high production costs (depending on the feedstock employed), and the available volume of the main feedstocks (principally vegetable oils, such as soy oil) is small relative to the corn market. This suggests that a major increase in demand for biodiesel could put substantial upward pressure on vegetable oil prices, and revive a “food versus fuel” controversy for the biofuels industry. Furthermore, the US biodiesel tax credit expired at the end of 2011, and without a resumption of incentives, demand will only grow slowly.

The universal adoption of a new midlevel ethanol-gasoline blend such as E15 (up to 15% ethanol, 85% petroleum gasoline) would be the easier route to incorporating more ethanol into the gasoline pool. With a homogenous fuel supply, consumer choice doesn’t enter into the equation other than on brand and price. The consumer does not have to make a choice between gasoline and an alternative fuel such as E85—the ethanol is already part of the gasoline pool and fueling infrastructure, and therefore invisible to the consumer.

In 2010, the EPA issued a final rule allowing the use of E15 gasoline blends in model year 2007 and newer light duty vehicles, and in early 2011 this was extended to all model years back to 2001. Vehicles newer than the 2000 model year comprise about 75% of the total light duty vehicle fleet currently in use (there are approximately 240 million vehicles in the total light duty fleet). Typically, newer vehicles are driven more than older vehicles, so the vehicles now allowed to consume E15 gasoline are estimated to have a capacity to consume more than 80% of the gasoline sold in the US.

Retail gasoline marketers have so far taken a cautious approach to the new E15 blend. Their concerns are mainly about the potential for motorists with older vehicles to misfuel, and the possible ensuing liability issues. Another marketer concern is the need to provide separate pump islands for E10 and E15. As of early 2013, very little E15 was being marketed in the US.

Future demand for E15 is also clouded by the issue of vehicle owner warranty concerns. Most vehicle warranties are valid only with the use of E10, so consumers with newer cars may opt for the E10 product to preserve warranty coverage. Owners of vehicles with expired warranties, however, may buy E15, but the typical issues of price, convenience, and range could limit the use of E15 in these vehicles. As RIN prices have risen in response to the E10 blend wall, so has the incentive for enterprising fuel marketers to supply E15. Marketers who successfully sell E15 (or perhaps E85, where practical) would be able to generate incremental RINs that could be sold at significant value to other obligated parties.

It remains to be seen how the RFS drama will play out. However, without raising the limit on blended ethanol, complying with the existing RFS, which requires a steady increase in the supply of biofuels to the transportation market through 2022, will be very difficult or impossible.

The longer-term RFS issue: the pace of new biofuel technology

The most problematic aspect of the RFS's advanced biofuel requirement is the slow progress seen in bringing cellulosic biofuels to market. As of Q1 2013, there are only two cellulosic biofuel production facilities that are expected to produce commercial volumes of fuel. The EPA projects that these facilities will produce about 14 million gallons of cellulosic fuel in 2013. Other production is limited to several small-scale demonstration cellulosic ethanol plants designed and built with the hopes of improving technologies that have been tested in laboratories. This suggests the RFS will need to be scaled back, given that the cellulosic requirement is scheduled to ramp-up aggressively to 16 billion gallons (1.04 million bd) by 2022.

The EPA administrator is given authority under EISA to lower the requirement if cellulosic ethanol is not commercially available. Each year since the original RFS2 went into effect, the EPA has reduced the cellulosic requirement dramatically. Even with the dramatically reduced requirement, EPA records show that during the 2010–2012 period, refiners and importers have almost entirely complied with the requirement by purchasing waiver credits from the EPA. This suggests that physical volumes have been practically non-existent.

To be sure, there are many private companies working on a multitude of advanced biofuel technologies, and technological breakthroughs might still result in greater commercial viability in the years ahead. What could change for the cellulosic biofuel industry to achieve greater success? The answer is simply that the technology needs to advance significantly. There are many different technologies being pursued to produce cellulosic biofuels—including production of ethanol from cellulosic plant material ("cellulosic ethanol"), drop-in fuels that are renewable but chemically similar or identical to petroleum fuels, and thermo-chemical approaches to producing renewable fuels. All remain high cost, and most have not proven the ability to scale up outside of the laboratory.

Looking simply at cellulosic ethanol technology, the techno-economic challenges to commercialization remain significant. Enzymes that break down biomass into sugars must become more efficient. Nature protects a plant's sugars by locking them in cellulose, which in turn is protected by a complex sheath of hemicellulose and lignin (the woody part of a plant that cannot be broken down). To remove this armor and further expose the cellulose, biomass is currently pretreated with harsh, energy-intensive thermochemical processes. Commercial viability requires more benign and lower-cost methods of accessing the cellulose. Once exposed, the cellulose is broken down into its constituent sugars by enzymes, but the process still remains relatively inefficient compared to the starch-to-sugar (corn-based ethanol) conversion process. Key signposts will include development of more robust and efficient enzymes and of microbes that can ferment all the sugars present in cellulosic material.

Despite near-term disappointments, the race to successfully commercialize next-generation biofuel technology continues. Indeed there are signs of progress. The US EPA's February 2013 Notice of Proposed Rulemaking identified five advanced biofuel plants that are now structurally complete and capable of either currently or eventually producing cellulosic biofuels (cellulosic ethanol as well as other types of fuels derived from cellulosic feedstock). The EPA has noted that production costs of cellulosic biofuels continue to fall as technology advances and manufacturing firms gain operational experience. Costs of producing cellulosic ethanol using enzymatic hydrolysis have reportedly fallen from a US$4-$8 per gallon range in 2007 to below US$4.

Project financing for the cellulosic biofuel industry has also improved relative to the last several years. The Great Recession of 2008–2009 and the subsequent slow recovery made it difficult for risky new biofuel ventures to raise the necessary funds for construction. However, the companies the EPA has identified as likely to produce over the next two years have either closed on government loan guarantees, executed successful IPOs, or have solid financial backing from large agro-industrial companies.

Indeed, 2013–2014 may represent a moment of truth for the nascent cellulosic biofuels industry. There remains considerable technological risk that the current facilities planning to produce fuel will fall short of their goals. On the other hand, the success of a handful of commercial-scale cellulosic biofuel facilities could result in a "virtuous circle" of greater operational knowledge, leading to declining operational and capital costs, and greater access to project funding for new capacity. The potential is there: the EPA notes that in addition to the facilities it has identified as likely to produce commercial volumes in 2013, there are several other facilities with a cumulative capacity of 100 million gallons that are currently targeting 2014 for commercial start-up.