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NEW ENERGY FINANCE

The Business Council for
Sustainable Energy®

SUSTAINABLE ENERGY in America 2013 Factbook

JANUARY 2013/ REVISED JULY 2013

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EXECUTIVE SUMMARY

A revolution is transforming how Americans produce, consume, and even think about energy. Traditional sources are in decline, while natural gas, renewables and energy efficiency are on the rise. These changes, which show no sign of abating, have far-reaching implications for US economic and national security interests. They are increasing the diversity of the country's energy mix, improving its energy security, and rapidly shrinking its 'carbon footprint' – a major positive development for addressing climate change.

Behind this revolution is a slew of new energy innovations, technologies, and applications. These include: newly applied techniques for extracting natural gas from shale rock formations; lower-cost and higher-efficiency photovoltaic panels for converting sunlight to electrons; highly efficient, natural gas end-use applications; vehicles fuelled by electricity and natural gas; and 'smart meters' that allow consumers to monitor, modulate, and cut electricity consumption.

This Factbook – researched and produced by Bloomberg New Energy Finance and commissioned by the Business Council for Sustainable Energy – offers a fresh look at the state of US energy along with the roles these new technologies and innovations now play. Its goal is to offer simple, easy-to-understand benchmarks on the contributions these new energy technologies are making today. It also provides information on finance and investment trends in clean energy resources.

What's unique about this Factbook

- First, the report is **quantitative and objective**, intended to arm policy-makers, journalists, and industry professionals with up-to-date, accurate market intelligence.
- Second, the report looks at **clean energy broadly defined**. The Factbook takes the pulse of the wide range of clean energy industries represented by the Council, including natural gas, renewable energy sources (including solar, wind, hydropower, geothermal, and biomass – but excluding liquid biofuels), distributed power, and energy efficiency.
- Third, the report **fills important data gaps**. For example, data sources and economic models of the US energy industry often fail to capture the full contribution of sectors such as distributed generation. This Factbook seeks to quantify accurately some sectors that are currently small but growing rapidly.

The US energy sector is undergoing dramatic change

- Total energy use fell 6.1% between 2007 and 2012, driven largely by advances in energy efficiency.
- Use of natural gas and renewable energy has increased, while other major energy sources such as coal and oil have experienced significant declines. Natural gas provided the US with 27% of its total energy supply in 2012, and renewables (including hydropower) supplied 9.3%.
- In the electricity sector, lower- and zero-carbon power sources are growing. Natural gas-fired power plants provided 31% of US electricity in 2012, up from just 22% in 2007. Renewable energy generation has meanwhile grown from 8.3% to 12.1% over that period. These technologies, which include wind, solar, geothermal and hydropower, represented the largest single source of new capacity growth in 2012, with more than 17GW added.

Factbook highlights

- *The need for reliability will increasingly be met by the advantages of flexibility.* Ensuring ongoing reliability will become an even tougher challenge for electricity market operators and regulators, given the diminished role for coal and the increased presence of variable resources (ie, intermittent renewables). Yet other changes afoot – including reduced electricity demand through energy efficiency; the introduction of smart grid technologies for improved grid management; and the growing role for dispatchable resources such as natural gas plants, hydropower, and demand response – can help the electricity industry meet this challenge. Still, most market structures do not yet fully recognize the benefits of some of the technologies offering increased flexibility, such as energy storage.
- *The shift in the US energy sector is not just about technologies and fuels, but also about markets.* The country's power sector – long skewed towards large, centralized systems such as coal plants – is beginning to open up to a wide range of small, distributed power generators, including combined heat and power (CHP) generators (mainly fuelled with natural gas), and fuel cells, and small-scale renewables. In addition, electricity market structures are evolving: over the past decade, 40 states have passed policies that enable profits to be decoupled from the amount of energy (electricity, natural gas, or both) that private utilities sell, in order to encourage economical investment in improved efficiency.
- *Estimated total new investment in US clean energy was $44.2bn in 2012.* This amount, which includes investments in most renewable and energy efficiency technologies but excludes natural gas, is well above the $10.4bn figure from 2004, when Bloomberg New Energy Finance first started tracking these investments. However, it marks a 32% decline from 2011, largely due to uncertainty over the fate of certain federal incentives that support financing for renewables.
- *Total US installed capacity of natural gas (442GW) plus renewables (187GW) is now at 629GW (58% of the total power generating mix) – up from 605GW (56%) in 2011 and 548GW (54%) in 2007.* Between 2008 and 2012, the US nearly doubled its renewables capacity from 44GW to 86GW (excluding hydropower, which itself is the single largest source of renewable power, at 101GW as of 2012). Recent years have also seen rapid growth in digital energy controls (eg, smart grid deployments and demand response controls), and energy efficiency (eg, building retrofits). Some sectors have seen relatively low deployment thus far but have the potential to

have a major impact: these include fuel cells, storage technologies other than pumped hydropower, and carbon capture and storage (CCS).

- *Natural gas is in the midst of a remarkable boom.* The emergence of new technologies has enabled the commercially viable extraction of unconventional natural gas resources including shale – a domestic, abundant, low-cost fuel (a mild winter in 2011-12 pushed prices down even further). Utility investments into natural gas infrastructure – such as pipelines, compressors, and meters – totalled $17bn in 2011.

- *Low natural gas prices can both complement and conflict with other energy sources.* For wind power in particular, cheaper gas has made it difficult to compete economically, though the one-year extension of the Production Tax Credit in 2013 has strengthened the business case for wind in the short term. Yet gas generators, which are inherently flexible technologies that can be easily ramped up and down to meet demand, are natural counterparts for variable resources such as wind and solar. Other options, such as combined heat and power (CHP), and fuel cell installations, which draw on natural gas for fuel, have become more competitive as natural gas prices decline.

- *The levelized costs of electricity for renewable technologies have plummeted.* For example, the cost of electricity generated by cost-competitive large solar power plants has fallen from $0.31 per kilowatt-hour in 2009 to $0.14 per kilowatt-hour in 2012, according to Bloomberg New Energy Finance's global benchmarking analysis based on already financed projects from around the world. (These figures exclude the effect of tax credits and other incentives, which would bring those costs down even lower.) Over the same period, the cost of power from a benchmark large wind farm has fallen from $0.09 in 2009 to $0.08 per kilowatt-hour.

- *Energy efficiency is making its mark on the grid and on buildings.* Since 1980, energy intensity of commercial buildings has decreased by over 20%, propelled by technology improvements and efficiency standards, such as those that apply to heating and cooling units and to thermal performance (ie, insulation). Electricity intensity has increased by less than 1% annually over the past 20 years despite the proliferation of electricity-consuming appliances in modern buildings. Overall, US utility budgets for energy efficiency reached $7bn in 2011 (the latest available date for which data exists). Demand response capacity, which typically involves the curtailment of electricity consumption at times of peak usage, has grown by more than 250% between 2006 and 2011, allowing major power consumers such as manufacturers to cut their energy costs and utilities to scale back production from some of the costliest power plants. Some 46m smart meters have been deployed in the US, while spending on smart grid roll-outs hit $4.3bn in 2012, up from $1.3bn in 2008.

- *Policy is potent.* Though the levelized costs of electricity of many renewable generation technologies have fallen drastically, most of these technologies still rely on incentives to compete. State-level mandates have been important drivers for renewable growth in the US, though in the case of most states, quotas for the next several years have already been satisfied. Policy measures have also helped further the cause of energy efficiency: Energy Star-certified commercial building floor space has increased by 139% from 2008 to 2012, and the stringency of building air conditioning efficiency standards has increased by up to 34% since 2005. Public funding for research and large-scale projects has also been a major driver of CCS activity. There are, however, some clean energy technologies which are ready (or on the brink of being ready) to operate in the marketplace without any incentives or policy directives at all.

- *Evolution of the transport sector mirrors that of power.* The country's ground transport sector is undergoing its own transition prompted by advances in technology and new fuel economy requirements. Corporate average fuel economy (CAFE) standards calling for the efficiency of US light-duty vehicles are scheduled to nearly double by 2025 compared with the 2011 average. Hybrids, plug-in electrics, and natural gas vehicles are growing in prominence; sales for the first two reached 488,000 vehicles in 2012 (3.25% of US passenger vehicle sales), and natural gas use in the transport sector (particularly among buses and light trucks) increased by 26% over 2008-11. In addition, a number of major automakers are aiming for commercial roll-out of fuel-cell electric vehicles by 2015. These developments, along with a growing role for biofuels, have driven gasoline consumption down 5.7% from its 2007 peak. These advanced vehicles largely still rely on incentives to be economical.

- *One winner from all of these developments is US air quality.* Reduced air pollution and emissions of greenhouse gases are a welcome consequence of the changes underway in the country's energy mix. The reductions in coal generation, ascendancy of gas, influx of renewables, expansion of CHP and other distributed power forms, adoption of demand-side efficiency technologies, rise of dispatchable demand response, and deployment of advanced vehicles are all contributing to the decline in carbon emissions from the energy sector (including transport), which peaked in 2007 at 6.02Gt and have dropped by 12% since. They are now at their lowest level since 1994.

SECTION 1. INTRODUCTION

As the title implies, this 'Factbook' aims to provide a snapshot of the role played by 'sustainable energy' technologies in US energy as of the end of 2012. Its goal is to offer simple, easy-to-understand benchmarks on their contributions. Where available, it also provides financial information on the amount of funds deployed over the past five years in support of these technologies.

The report is divided into seven sections. The first provides an overview of the US energy sector and depicts how dramatically it has changed in the past five years as these new energy technologies have taken on greater importance; it also presents an overview of policy, economics, and financing across the entire sector. The second specifically looks at the ascendancy of natural gas as a power-generation source in the US. The third examines the contributions of renewable energy technologies to the power grid via large-scale power-generating projects. The fourth turns to small-scale power generation and storage from installations such as residential photovoltaic systems, CHP systems, and stationary fuel cells; it also investigates the current state of the market for carbon capture and storage, a technology which many perceive to be crucial for long-term climate change strategy. The fifth section is dedicated to energy efficiency, and technologies and mechanisms for reducing electricity demand. The sixth looks at how the US transportation is being affected by a proliferation of electric vehicles and by other technologies. Lastly, the seventh extracts and elaborates on themes common across many sectors.

Most of the data presented has been compiled by Bloomberg New Energy Finance – the world's leading research firm tracking investment, deployment, and policy trends in the energy markets. In many cases, these are original datasets gathered and managed by the company's 200 researchers, reporters, and analysts in 13 countries around the world, including in New York, Washington and San Francisco.

This report has been generously underwritten by the Business Council for Sustainable Energy – a coalition of companies and trade associations from the energy efficiency, natural gas and renewable energy sectors. The Council also includes independent electric power producers, investor-owned utilities, public power, commercial end-users and project developers and service providers for environmental markets. Membership organizations provided additional datasets for use in this report. Bloomberg New Energy Finance compiled, wrote, and edited this report and retained editorial independence and responsibility for its content throughout the process.

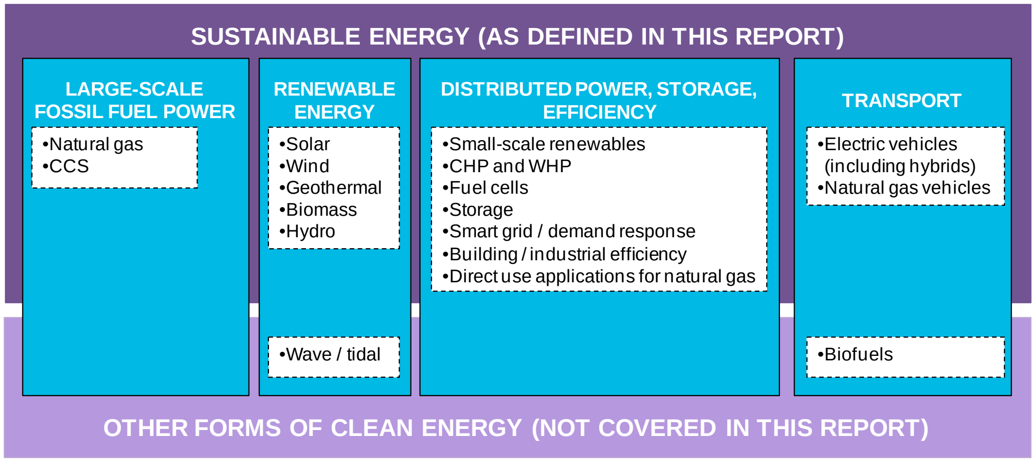
A note on terms used in this report

The focus of this report is the technologies deployed today to transform how the US produces, consumes, and stores energy. These technologies take myriad forms and are not easily classified under a single, all-encompassing title. Some are renewable in the strictest sense in that they produce power using resources that are naturally replenished and without emitting any harmful emissions into the atmosphere. Others do produce CO2 but in lower quantities than the incumbent sources against which they compete. Still others help to cut the amount of energy consumed and result in lower CO2 emissions indirectly.

This report specifically focuses on the following fuels, technologies, processes, or techniques: natural gas; renewables defined as wind, solar, geothermal, biomass, and hydropower generation; CHP and fuel cells; carbon capture and storage; energy storage; digital energy, demand response, and energy efficiency; and electric and natural gas-powered vehicles. Throughout the report, these are referred to as forms of '*sustainable energy*'. In some cases the technologies have been established for years, but what makes those older technologies new is the scale to which they are being applied to today's energy challenges.

Figure 1 depicts the sectors captured under 'sustainable energy' and notes other sectors which are occasionally included in the 'clean energy' umbrella but which are not analyzed in this report.

Figure 1: Understanding terminology for this report



Source: Bloomberg New Energy Finance, Business Council for Sustainable

SECTION 2. A LOOK ACROSS THE US ENERGY SECTOR

The US energy sector has been undergoing dramatic change. For many years, coal was the workhorse behind US power, with additional sizable contributions coming from natural gas, nuclear, and hydropower. But now, coal generation is falling while gas, renewables and energy efficiency are gaining share. Natural gas's contribution to US power grew from 22% to 31% between 2007 and 2012. Renewable energy is also in the midst of a remarkable growth period; total installed capacity (excluding hydropower) nearly doubled in the five years between 2008 and 2012, from 44GW to 86GW.

2.1. US energy sector: a bird's-eye view

Total energy use fell 6.1% between 2007 and 2012, according to preliminary estimates, driven largely by advances in energy efficiency. This decrease occurred in spite of a 2.9% increase in GDP over the same period. Though energy use overall is falling, the use of natural gas and renewable energy have increased, while other major energy sources such as coal and oil have experienced significant declines. Natural gas provided the US with 27% of its total energy supply in 2012, and renewables (including hydropower) supplied 9.3% (Figure 2).

Much of the overall energy reduction has come from sectors outside electricity. Over 1990-2012, while total energy consumption grew by a compound annual growth rate (CAGR) of just 0.5%, electricity demand grew more than twice as quickly at 1.4% (Figure 3). Non-electricity energy demand has slowed or fallen due to factors including increased vehicle fuel economy, which has reduced oil consumption since 2005, and more efficient heating systems and buildings, which have kept residential and commercial natural gas consumption flat.

Figure 2: US primary energy consumption vs GDP, 1990-2012

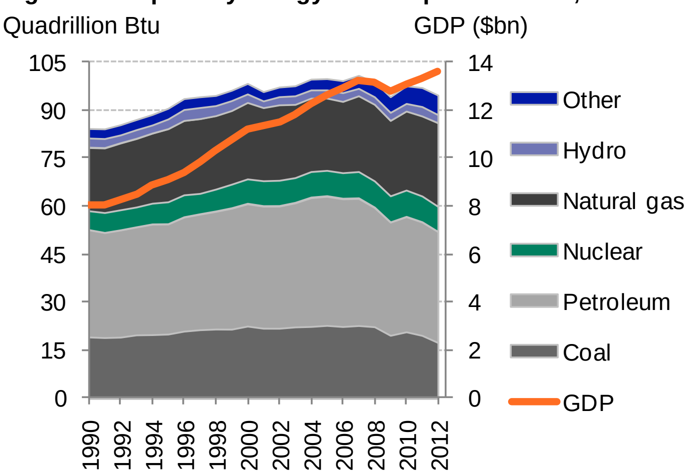
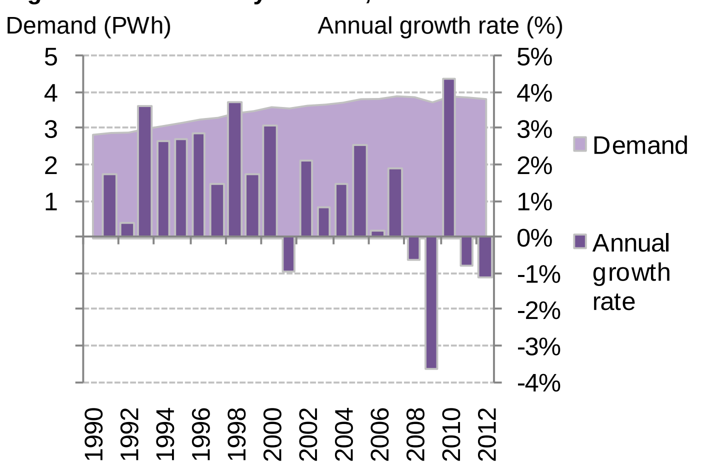


Figure 3: US electricity demand, 1990-2012



Source: Bloomberg New Energy Finance, Bureau of Economic Analysis, US Energy Information Administration (EIA). Note: GDP is real and chained; 2012 value is based on economic forecasts from Bloomberg Terminal. PWh stands for petawatt-hours (billion MWh).

In the electricity sector, lower- and zero-carbon power sources are growing. Natural gas-fired power plants provided 31% of US electricity in 2012 – up from just 22% in 2007. Meanwhile renewable energy generation has grown from 8.3% to 12.1% over that period. (Figure 4)

Fuel-price economics and supply-demand characteristics of the electricity markets explain natural gas's expanded share. In situations of excess capacity, different fuels compete against each other, especially when short-term substitution is possible. In the US electricity sector, this substitution is made possible by two phenomena:

- Reserve margins – the amount of total available generating capacity over and above annual peak demand – are currently quite high across most of the US. This is because, prior to the 2008 recession, overoptimistic demand projections and inexpensive financing led to overbuild. High reserve margins mean that electricity markets rarely utilize their full portfolio of generation supply.
- US electricity demand is highly seasonal, with a large summer peak, a smaller winter peak and two 'shoulder' seasons where demand drops to very low levels (intraday demand is also highly variable). This separates power plants into three broad classes: baseload generators, which run for more than 70% of the year; intermediate generators, which run between 15% and 70% of the year; and peakers, which only run during peak hours.

With sufficient supply to meet demand, markets choose which plants to run; naturally, the lowest-cost plant is selected to provide electricity. Because of cheap natural gas, combined-cycle gas plants (CCGTs) have become more competitive with existing coal plants and increased their run hours. In fact, in April 2012, electricity generation from natural gas equalled that from coal for the first time in US history.

Figure 4: US electricity generation by fuel type, 2007-12 (%)

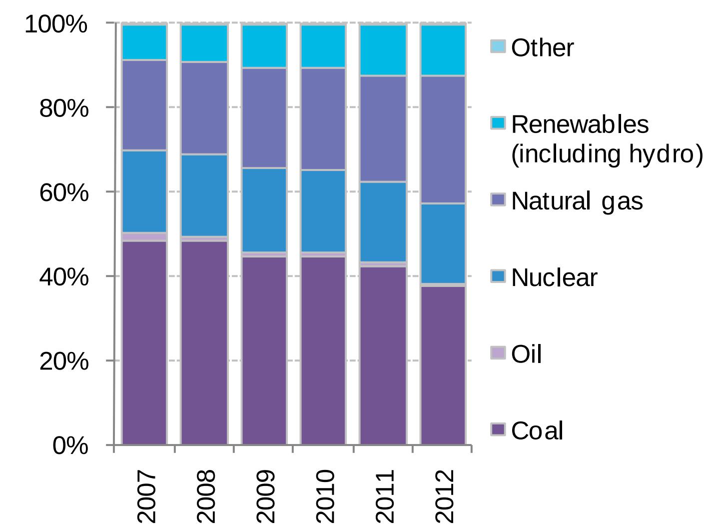
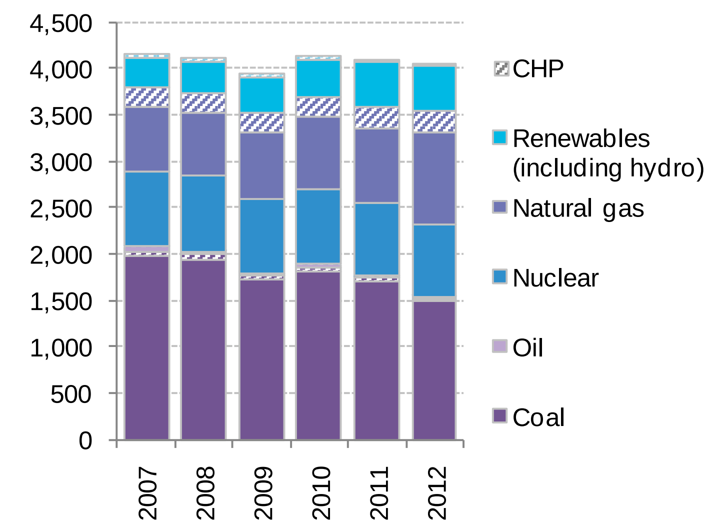


Figure 5: US electricity generation by fuel type, 2007-12 (TWh)



Source: Bloomberg New Energy Finance, EIA Notes: In Figure 4, contribution from 'Other' is minimal and consists of miscellaneous technologies including hydrogen and non-renewable waste. In Figure 5, contribution from CHP is indicated by a 'shaded' bar in the columns.

These factors explain the growth of natural gas in the power sector on the basis of fuel prices (which drive operating costs). More structural (ie, less price-sensitive) growth stems from the lower capital cost of a CCGT project compared with coal plants. This has made natural gas the fuel of choice for new build (Figure 6). In addition, older, less-efficient coal plants have retired.

New build for renewables has also been substantial. In fact, in 2012, renewables – including wind, solar, geothermal, hydropower, and other technologies – represented the largest single source of new capacity growth, with more than 17GW added. Of this volume, 13.7GW came from the wind industry, as its key incentive was on the verge of expiring (Figure 7).

Figure 6: US capacity build by fuel type, 1990-2011 (GW)

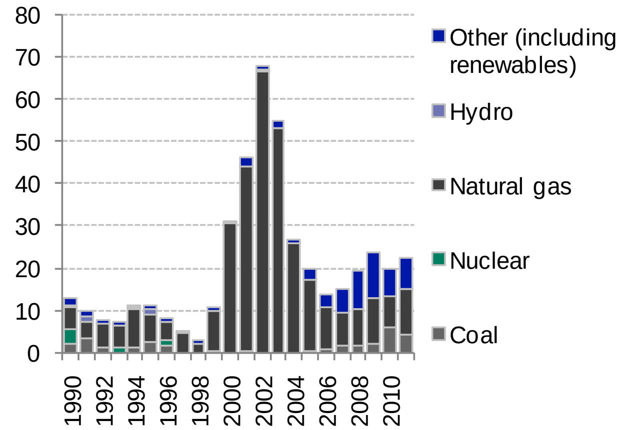
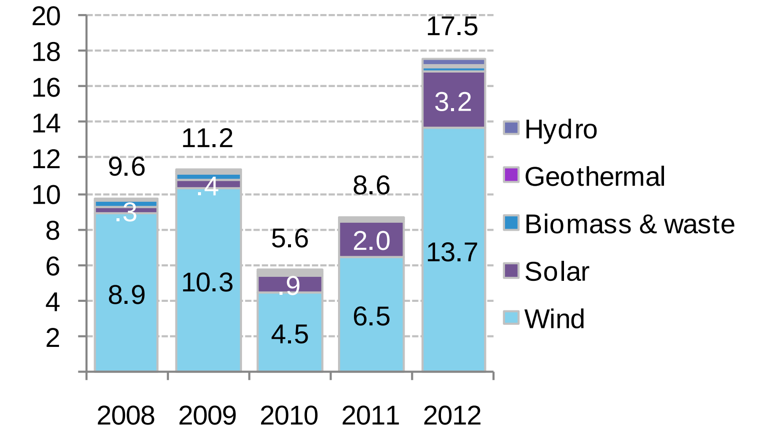


Figure 7: US renewable capacity build by technology, 2008-12 (GW)



Source: Bloomberg New Energy Finance, EIA, FERC Note: Figures for official capacity additions for later years not yet available. New natural gas build also includes oil generating capacity; the EIA does not differentiate between the two, but the vast majority of new natural gas/oil capacity is devoted to natural gas generation. In 2012, new biomass and waste capacity totalled 218MW, new geothermal capacity totalled 147MW, and new hydropower capacity totalled 19MW.

The end of 2012 finished with 86GW of operating renewable *capacity* (Figure 8). Cumulative installed renewable capacity nearly doubled between 2008 (44GW) and 2012 (86GW) (Figure 9). Over the same period, renewable *generation* increased from 126TWh in 2008 to 219TWh in 2012 (375TWh in 2008 and 491TWh in 2012 including hydropower) (Figure 10 and Figure 11).

Figure 8: US cumulative renewable capacity by technology (including hydropower), 2008-12 (GW)

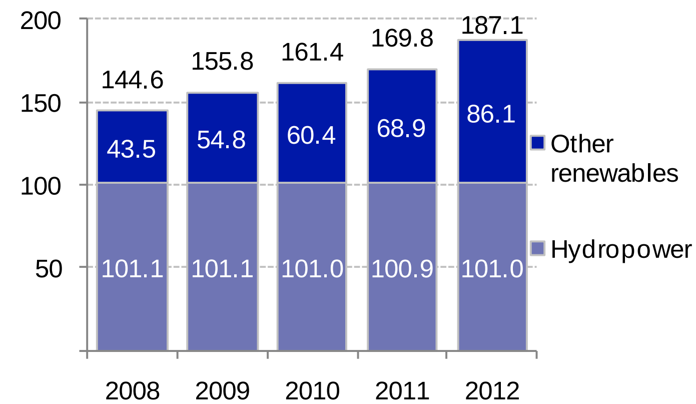
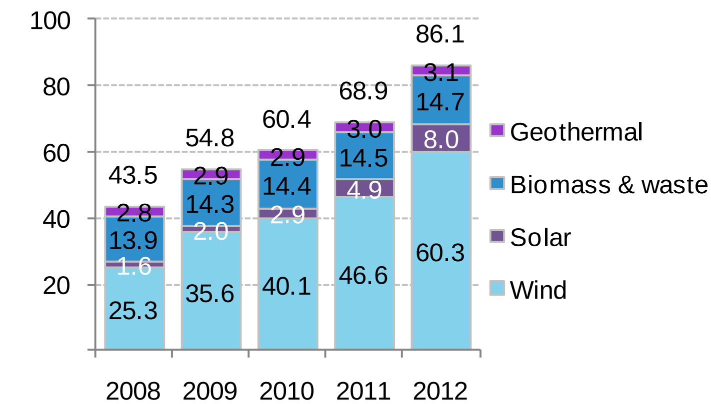


Figure 9: US cumulative non-hydropower renewable capacity by technology, 2008-12 (GW)



Source: Bloomberg New Energy Finance, EIA Note: Hydropower capacity includes pumped storage

Figure 10: US renewable generation by technology (including hydropower), 2008-12 (TWh)

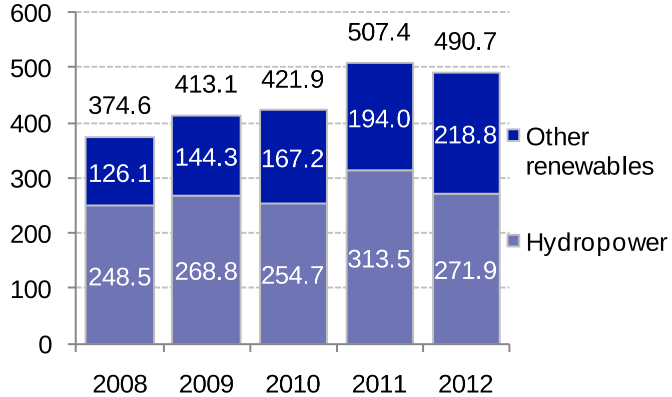
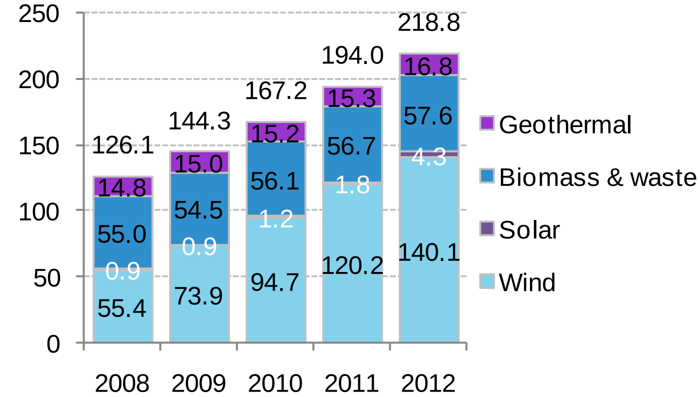


Figure 11: US non-hydropower renewable generation by technology, 2008-12 (TWh)



Source: Bloomberg New Energy Finance, EIA Note: Includes net energy consumption by pumped hydropower storage projects.

2.3. Policy

The US generally lacks an over-arching policy framework for furthering the deployment of sustainable energy technologies. It has set no formal national goals for expanding sustainable generating capacity or for cutting harmful greenhouse gas emissions from the energy sector, for instance - though the Environmental Protection Agency is in the midst of establishing emission-related regulations for the sector. Still, a patchwork of federal laws and regulations and critical state-level policies has lent important and substantial support to the sector. Much to the frustration of the sustainable energy sectors, however, many of these policies, such as key federal incentives for renewables, lack permanence – creating unnecessary uncertainty in the marketplace.

For many sectors, it is not just state and federal incentives, but also *regulatory* policy governing the functioning of electricity markets that is a vital concern. For example, demand response fares best in structures that enable it to compete fairly against traditional generation to serve the market's capacity needs. Renewables benefit from retail electricity markets that allow competition, so that customers can choose to have some or all of their power come from 'green' sources (ie, renewable power, or fossil-fired generation that is offset by the procurement of renewable energy credits). The economics for storage would be greatly enhanced by markets that monetized their abilities to ramp quickly or to absorb excess generation. Regulatory policy varies widely across the country.

A deeper investigation of the specific policies supporting the distinct technologies covered in this report is presented in the sections corresponding to each of those technologies.

2.4. Finance

Bloomberg New Energy Finance has been tracking investments in clean energy globally since 2004. In the US, following pullback in deal flow due to the 2008 financial crisis, investment volume in clean energy grew from 2009-11 (Figure 12) in part due to stimulus support and increased cost competitiveness; investments in US clean energy then slid in 2012 as some important incentives for renewable projects had expired the previous year (2011) and continuation of others was uncertain.

Asset financing – the funding of projects and plants – experienced a spike in 2011 as developers closed financing prior to the expiration of key incentives (Figure 13). Also, a portion of the record-high deal volume was supported by the Department of Energy's (DOE) $16.1bn loan guarantee program, which ended in September 2011.

The focus of asset financing has shifted several times since 2004. First, it was biofuels, receiving 40% of all asset finance in 2004–07 as developers constructed ethanol plants (motivated both by a federal mandate for biofuels blending and by the fact that ethanol could serve as a substitute for an oxygenate that was banned in 2005). Wind gained prominence in 2008-10 as it was the cheapest form of generation for utilities fulfilling compliance with renewable electricity mandates. Plunging costs for modules helped turn the focus to solar in 2011-12.

Figure 12: Total new US investment in clean energy, 2004-12 ($bn)

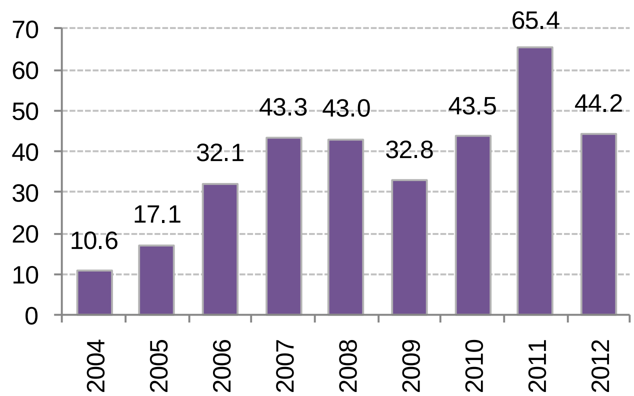
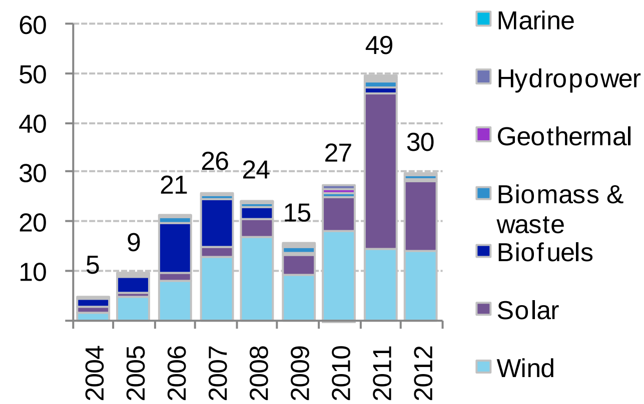


Figure 13: US asset finance investment in clean energy by sector, 2004-12 ($bn)



Source: Bloomberg New Energy Finance Notes: Figure 12 shows total clean investment in the US across all asset classes (asset finance, public markets, venture capital/private equity), as well as corporate and government R&D and small distributed capacity. Values in both figures include estimates for undisclosed deals and are adjusted to account for re-invested equity. Clean energy here means: renewable energy, energy smart technologies (digital energy, energy efficiency, fuel cells, storage, advanced transportation), and other low-carbon technologies and activities (carbon markets value chain, companies providing services to the clean energy industry). Asset finance estimates for large hydro are only available for 2009-12.

The US is the dominant leader in *venture capital and private equity* (VC/PE) for clean energy. Since 2004, US VC/PE firms have invested $36bn in clean energy (Figure 14).

In contrast, the *public markets* have suffered dismally in recent years (Figure 15). Poor clean energy stock performance, chronic oversupply among upstream manufacturers, and uncertainty surrounding future incentives has constrained public market appetite. Year-on-year growth has not been positive since 2006/07, and total public market investment amounted to only $1.6bn in 2012, far from the record-high $7bn in 2007.

Figure 14: US VC/PE investment in clean energy by sector, 2004-12 ($bn)

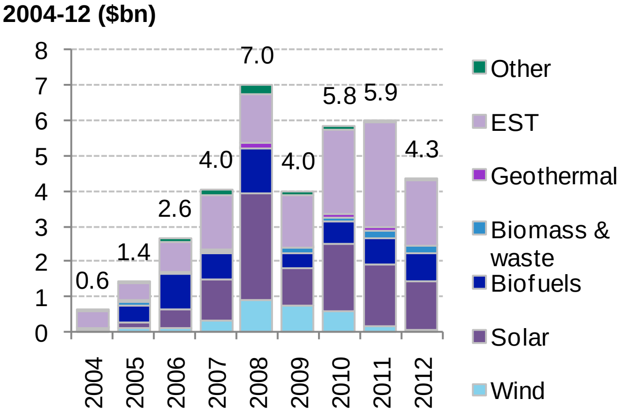
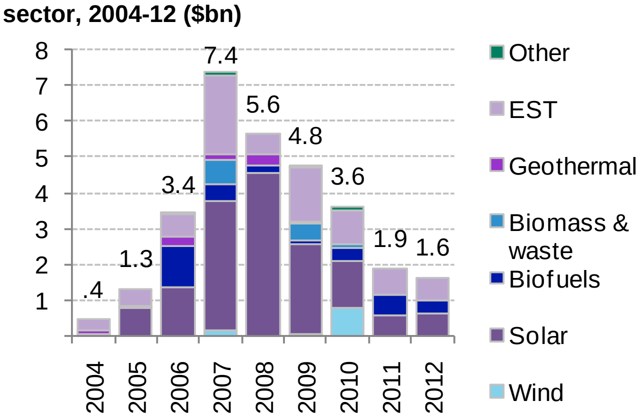


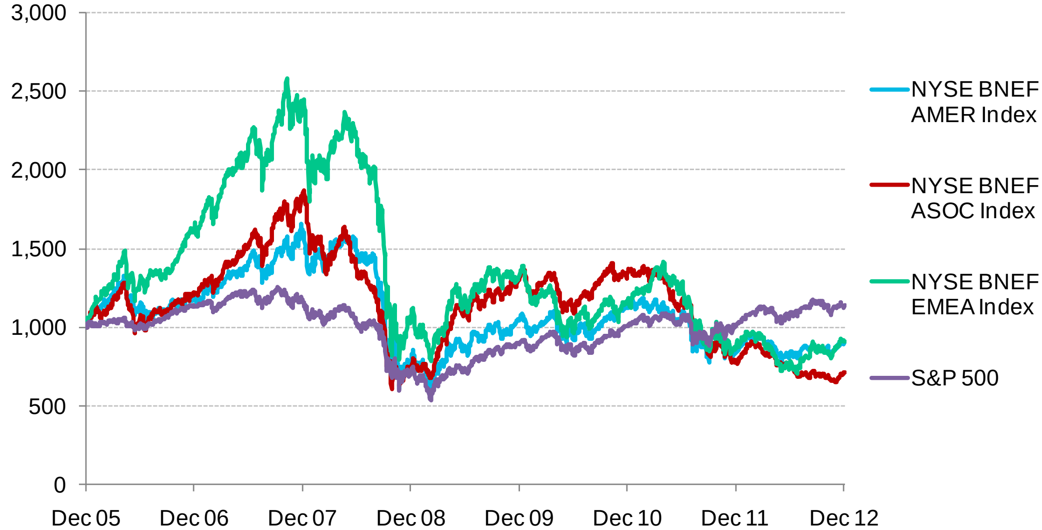
Figure 15: US public market investment in clean energy by sector, 2004-12 ($bn)



Source: Bloomberg New Energy Finance Notes: Definition for 'clean energy' is provided below Figure 12. Values in Figure 14 include estimates for undisclosed deals.

Bloomberg New Energy Finance maintains the NYSE BNEF Americas Index – an index of clean energy stocks for companies in the Americas; the index has 80% exposure to US companies (the remaining 20% are in other countries, including 9% in Brazil). In the period leading up to the market crash of 2008, the index outperformed the S&P 500, but returned less than those that track clean energy stocks in Europe, Middle East and Africa (EMEA), and in Asia and Oceania (ASOC). Since the trough bottomed out in March 2009, the AMER index has outperformed the other two regions on a normalized basis, but all three have underperformed broader market indexes (Figure 16).

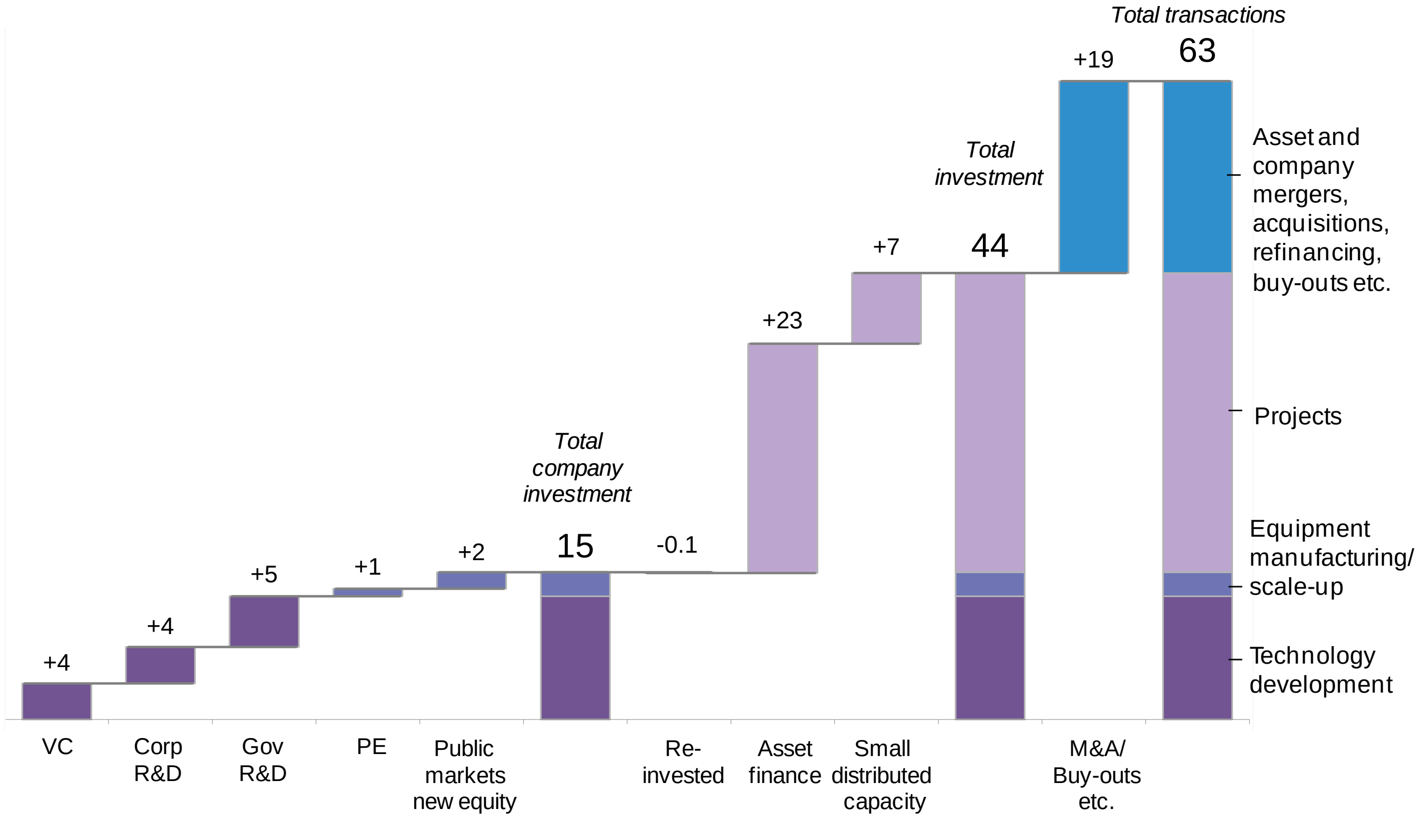
Figure 16: NYSE BNEF Regional Indexes, as of end-2012 (normalized returns)



Source: Bloomberg New Energy Finance, NYSE Notes: Values as of December 30 2012; rebased to 1000 on 30 December 2005.

Figure 17 breaks down the different *types* of investment (eg, venture capital, asset finance) flowing into the US clean energy sector.

Figure 17: Clean energy investment types and flows in the US, 2012 ($bn) (as per Bloomberg New Energy Finance definition of clean energy)

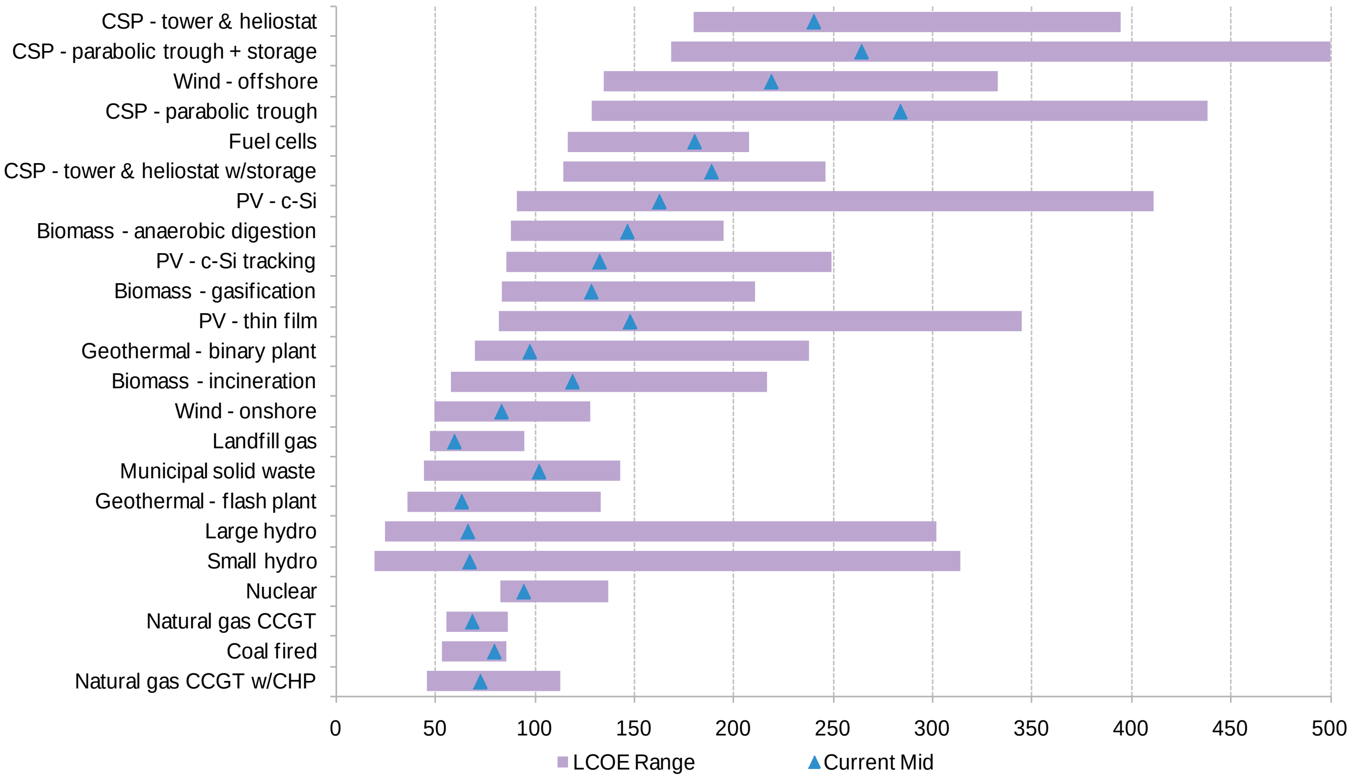


Source: Bloomberg New Energy Finance Notes: See Figure 12 for definition of 'clean energy'. No hydropower asset finance data is available for 2012.

2.5. Economics

The Bloomberg New Energy Finance levelized cost of electricity (LCOE) analysis compares the cost of producing electricity from 23 technologies, and incorporates the costs of equipment, capital, and operation (Figure 18). This analysis takes a global view and is not specific to the US, and it reflects costs prior to the inclusion of policy support. Overall, the analysis indicates that many renewable energy technologies require support in order to be competitive with fossil-fuel-derived sources. It also shows that many technologies falling under 'sustainable energy' as defined in this report are already economically viable. The economics of specific technologies are further analyzed throughout this report.

Figure 18: Levelized costs of energy across power generation technologies, Q4 2012 ($/MWh)



Source: Bloomberg New Energy Finance, EIA. Note: LCOE is the per-MWh inflation-adjusted lifecycle cost of producing electricity from a technology assuming a target equity internal rate of return (IRR) of 10%. All figures are derived from Bloomberg New Energy Finance analysis. Analysis is based on numbers derived from actual deals (for inputs pertaining to capital costs per MW) and from interviews with industry participants (for inputs such as debt/equity mix, cost of debt, operating costs, and typical project performance). Capital costs are based on evidence from actual deals, which may or may not have yielded a margin to the sellers of the equipment; the only 'margin' that is assumed for this analysis is 10% equity IRR for project sponsor.

SECTION 3. NATURAL GAS

In five short years, consensus has taken a 180: after companies spent billions on import facilities to prepare for the inevitable decline of US natural gas production, improved hydraulic fracturing and horizontal drilling techniques began to unlock a bounty of shale and tight natural gas, and the industry is now even preparing for a future in which the US would be an exporter of natural gas. Natural gas production has grown by about 14 billion cubic feet a day (Bcfd) – or around 25% – over the past five years. Demand has struggled to keep up – despite strong growth from the power sector – which has led net imports and prices down.

3.1. Policy

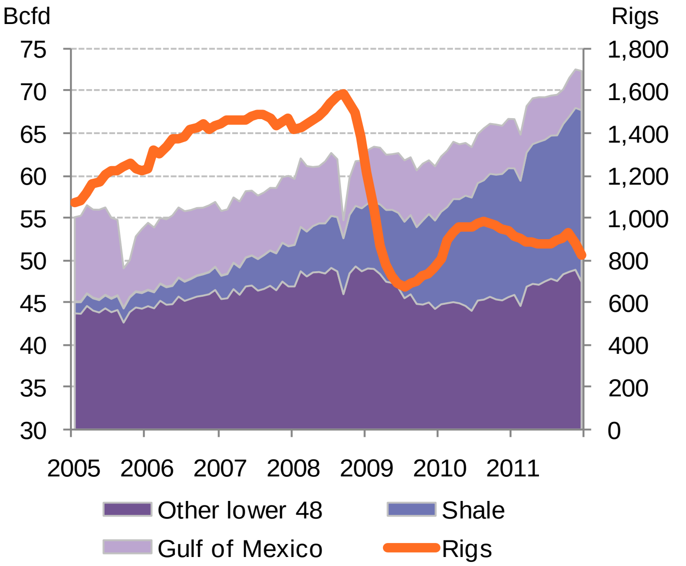
The policies that most affect natural gas consumption in the power sector are actually directed at coal-fired power plants. Two rules promulgated by the Environmental Protection Agency (EPA) – the Mercury and Air Toxics Standards (MATS) and the currently vacated Cross-State Air Pollution Rule (CSAPR) – will force scores of coal plants into retirement by mandating the installation of expensive environmental equipment (or by simply making it uneconomical for the plants to continue operating). Natural gas-fired generation stands to replace retired coal generation almost one to one, making MATS and CSAPR powerful demand drivers.

Other policy considerations for the natural gas industry relate to drilling regulations and incentives. As of the end of 2012, the only state with a moratorium on shale drilling (more precisely, on high-volume hydraulic fracturing) with a highly prospective shale resource is New York, which sits atop the northern portion of the Marcellus Shale. The EPA's New Source Performance Standards (NSPS) on Volatile Organic Compounds (VOCs) from fracked oil and gas wells will mandate the use of 'green completion' equipment on virtually all fracked wells by 2015. In terms of incentives, the industry has long enjoyed the federal tax deduction for intangible drilling costs (the 'IDC deduction'), which has been in place for decades and allows drillers to deduct what can amount to more than 75% of drilling and completion costs. This valuable deduction is currently a permanent feature of the tax code but that could come to an end. Other policies can incentivize the direct use of efficient natural gas appliances and vehicles.

3.2. Deployment

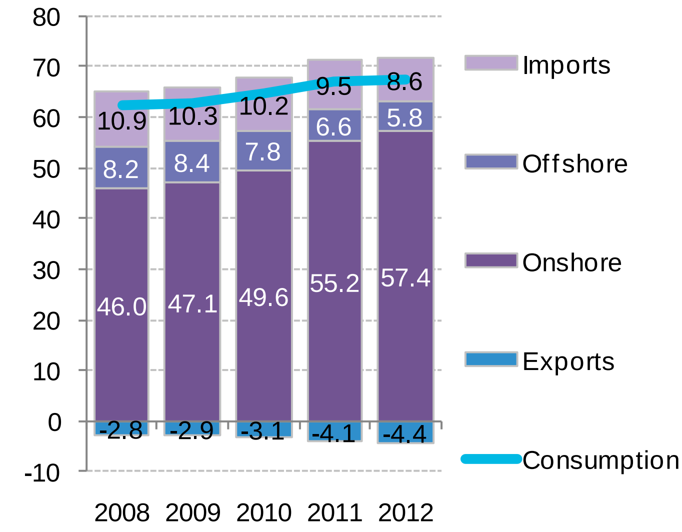
Over 2006-07, oil traded in the $60-75 a barrel range while natural gas fluctuated between $6 and $8 a million British thermal unit (MMBtu). This kept producers interested in exploiting US natural gas resources, with the gas-directed rig count and total production rising throughout the 2008 commodities boom (Figure 19). The crash that followed caused rig counts to decline precipitously, but production from shale plays continued to surge due to technical advancements. Over 2007-10, shale gas went from a marginal source of production to the lowest-cost resource. Meanwhile, natural gas prices dropped, making combined cycle gas plants (CCGTs) increasingly competitive with coal plants in the electricity generation market.

Figure 19: US gross natural gas production and gas-directed rig count, 2005-2011



Source: Bloomberg New Energy Finance, EIA, Baker Hughes

Figure 20: US dry natural gas supply (continental US only), 2008-12 (Bcfd)

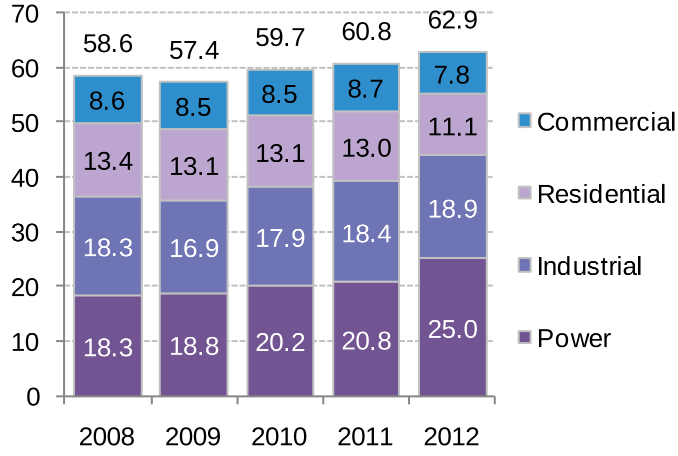


Source: Bloomberg New Energy Finance, EIA

Increased production has brought net imports down, virtually eliminating the need for imported liquefied natural gas (LNG) and eating into pipeline imports from Canada. Exports to Canada and Mexico, meanwhile, have risen (Figure 20). The increase in production has also contributed to lower natural gas prices and boosted coal-to-gas switching in the power sector (Figure 21) as well as greater consumption from the industrial sector. This increased use of natural gas by the power sector has been the principal driver of consumption growth, since this sector is most price-elastic. Demand from heating is almost completely price-inelastic, while demand from the industrial sector is generally price-elastic over the medium term (ie, companies eventually undertake capital investments).

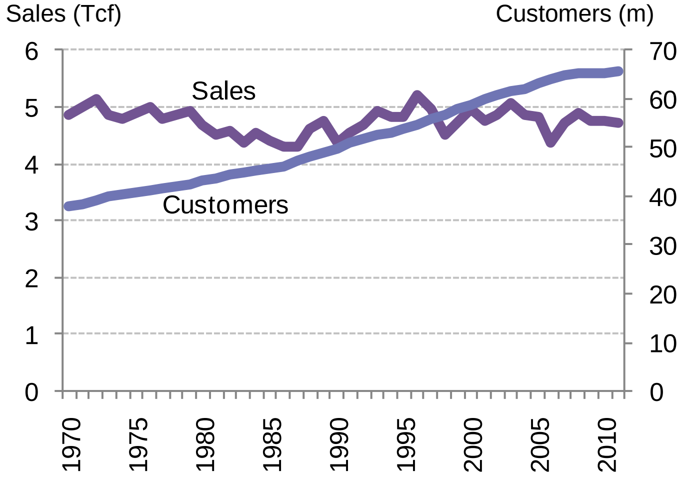
From 1970 to 2011 the number of residential natural gas customers increased by 73%, but improvements in energy efficiency have kept *total* residential natural gas sales fairly constant, between 4.29 and 5.21 trillion cubic feet (Tcf) (Figure 22). Overall, the average natural gas customer in 2011 uses just 56% as much gas as a customer in 1970.

Figure 21: US natural gas demand by end-use (industrial, commercial, residential), 2008-12 (Bcfd)



Source: Bloomberg New Energy Finance, EIA

Figure 22: US natural gas customers vs residential consumption



Source: Bloomberg New Energy Finance, American Gas Association

Table 1: Liquids content by play

Gallons of natural gas liquids (NGL) per thousand standard cubic feet of raw gas	
Eagle Ford (wet), Granite Walsh	5.0-6.0
SW Marcellus	3.5-5.5
Ardmore Woodford	4.0
Anadarko Woodford	3.0-4.0
Duvernay	2.5-3.5
DJ Basin	1.5-3.0
Barnett (wet)	2.0-2.5
Piceance	1.5-2.0
Arkoma Woodford, Montney	1.0-2.0
Uinta	0.5-1.5
Barnett (dry), Haynesville, Pinedale, Horn River, Antrim, Fayetteville, NE Marcellus	<0.5

Source: Bloomberg New Energy Finance, companies

Five of the ‘Big Six’ US shale gas plays (the Barnett, Haynesville, Eagle Ford, Woodford and Fayetteville) are located in the greater Mid-Continental Oil Province, though each lie in separate (sometimes several) basins, while the Marcellus is in the Appalachian Basin. The plays’ geological properties vary widely. Moreover, the advances in drilling technology that ‘unlocked’ these major shale plays have also made a range of tight gas, tight and shale oil, and carbonate plays economically viable.

Of all the variables, one that has been especially important over the past 18-24 months is the liquids content of the gas. ‘Wet’ or ‘rich’ gas contains a substantial volume of natural gas liquids (NGLs), which are valuable commodities. Producers are therefore paid more for wet gas than for dry gas, so liquids content helps drive upstream investment decisions. Table 1 shows the liquids content of US shale plays.

The drive towards wet gas plays has driven down prices for the lighter NGLs, especially ethane, which is used to make plastics. This, in turn, has led US ethylene crackers to switch away from heavier hydrocarbons in the naphtha range (5-10 hydrocarbons) to ethane and propane (Figure 23). North America is now the second-lowest-cost producer of ethylene in the world, outside of the Middle East. Meanwhile, low natural gas prices have also driven industrial users to use more of this fuel at their onsite generators (Figure 24), as well as for process heat and as feedstock.

Figure 23: US ethylene production by feedstock, 2008-11 (%)

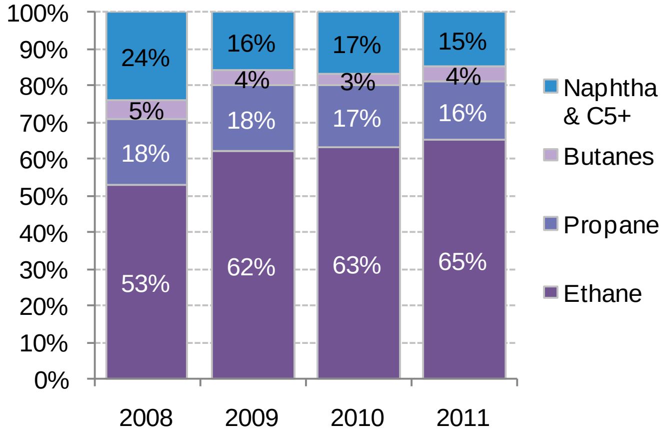
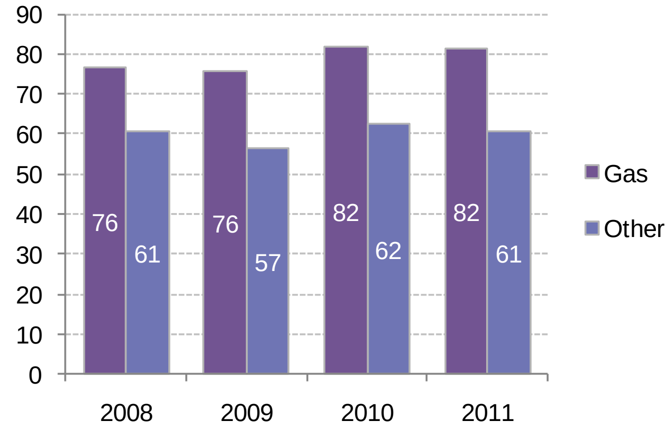


Figure 24: Industrial electricity production from onsite generation by source, 2008-11 (TWh)

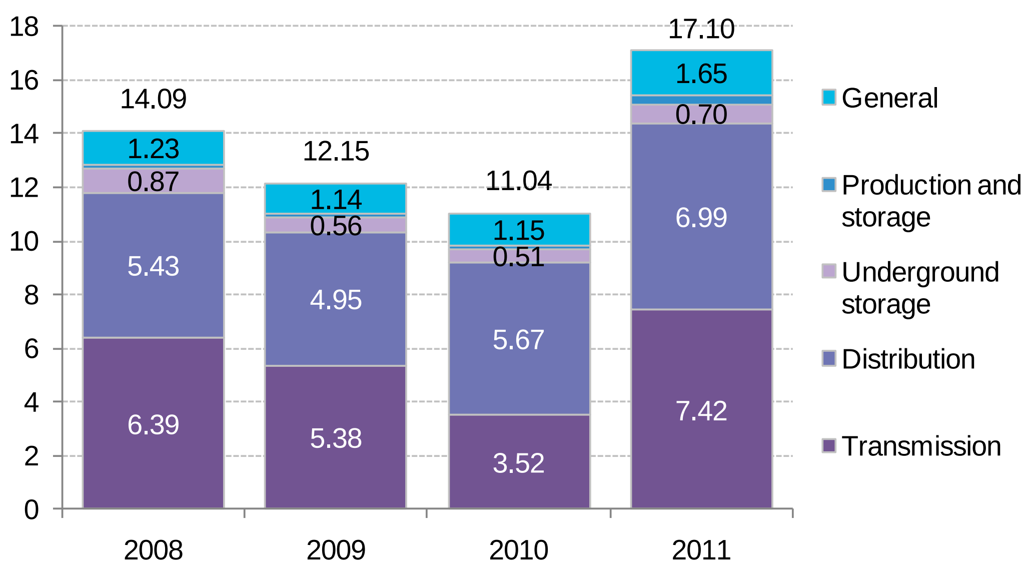


Source: Bloomberg New Energy Finance, EIA

3.3. Financing

The natural gas supply boom has sparked an upswing in investment (Figure 25). The bulk of growth was in the transmission space, which saw a 111% year-on-year increase in investment from 2010 to 2011. This was due in part to the ongoing development of the Marcellus play, where midstream infrastructure is not as developed as in traditional producing regions.

Figure 25: US utility construction expenditures for natural gas, 2008-11 ($bn)

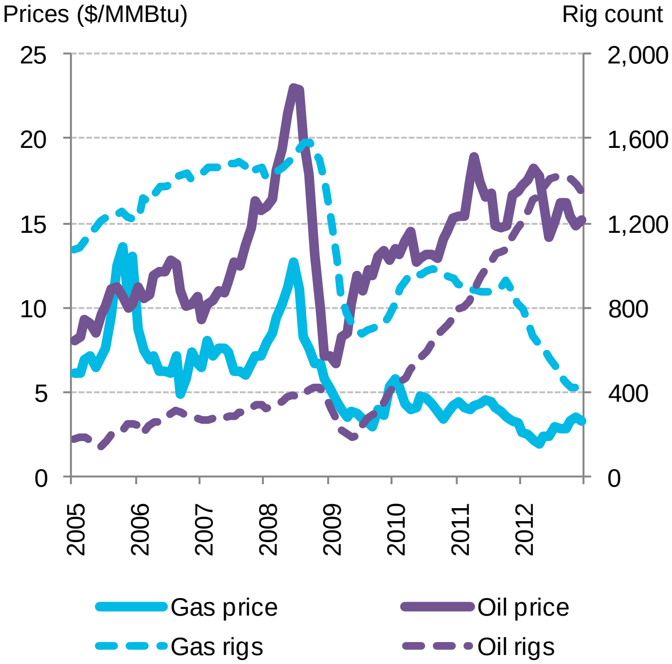


Source: American Gas Association Note: 'general' includes miscellaneous expenditures such as for the construction of administrative buildings.

3.4. Economics

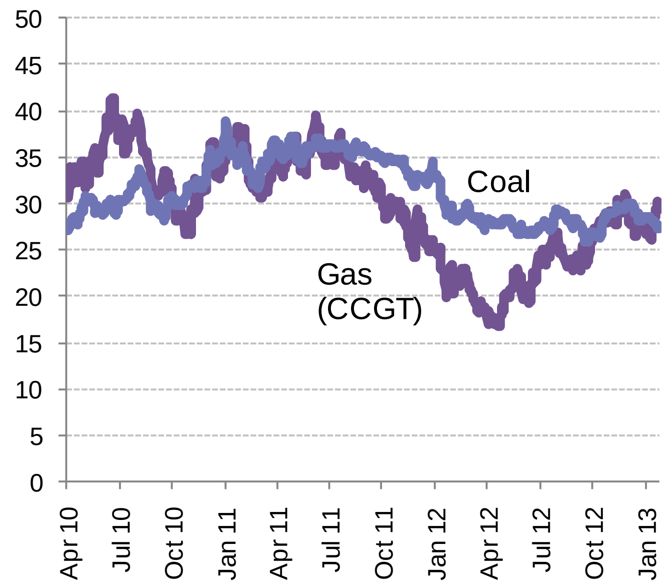
Over the past 18 months, natural gas prices have sunk to historical lows while oil prices have remained high (Figure 26). This incentivizes drillers to target oil or liquids-rich deposits. Meanwhile, on the demand side, those same low gas prices made the median CCGT plant cheaper to run than the median coal plant, causing a massive switch from coal to gas in the power sector (Figure 27).

Figure 26: US natural gas vs. crude oil prices and rig counts, 2005-12



Source: Bloomberg New Energy Finance, Baker Hughes

Figure 27: Cost of generating electricity in the US from natural gas vs coal, 2010-12 ($/MWh)



Source: Bloomberg New Energy Finance Note: Assumes heat rates of 7,410Btu/kWh for CCGT and 10,360Btu/kWh for coal (both are fleet-wide generation-weighted medians); variable O&M of $3.15/MWh for CCGT and $4.25/MWh for coal.

3.5. Market dynamics

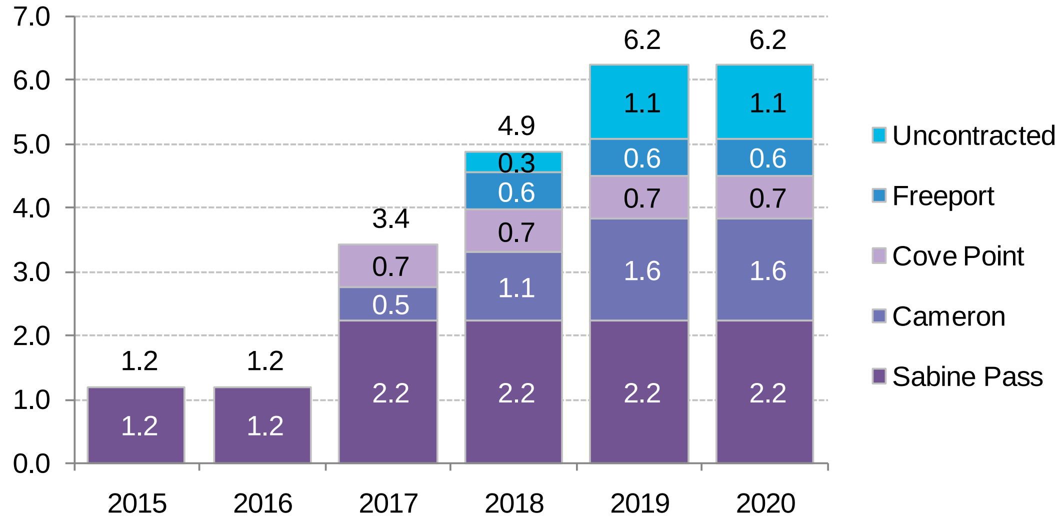
Producers with a large share of natural gas relative to liquids have suffered in the low price environment. After nine months of sub-$3 natural gas (with a brief exception for a short-lived July bounce), logic suggests that players would have cut production levels. While the natural gas-directed rig count has indeed fallen off a cliff, production has not budged. There are several reasons for this:

- Drilling remains profitable in oil and liquids-rich natural gas plays, which also produce substantial volumes of dry natural gas.
- A substantial amount of uneconomic drilling has been done to retain leased acreage (under some leasing contracts, producers are required to drill or they relinquish their rights to the asset).
- Drilling practices have improved markedly in recent years, with the total time needed to drill a horizontal well having dropped and a technique known as 'pad drilling' cutting down on days spent setting up and taking down rigs.
- There is still a large backlog of drilled but not yet completed wells, especially in the Marcellus. These will continue to be brought online as local takeaway capacity – ie, gathering systems – come online.
- The US natural gas market is highly fragmented, with hundreds of very small players with correspondingly small balance sheets. These companies cannot afford to shut in production in the face of low prices, as short-term cash flows are often sorely needed to meet interest payments.

The very low natural gas prices in 2012 were as much a result of an incredibly mild winter as structural overproduction. Because North America is a 'natural gas island' and cannot export, the only way to burn off surplus is by incentivizing demand from the power sector with extremely low prices.

Producers have thus begun seeking other sources of demand for US natural gas, including the export market. Companies are looking to repurpose existing (and unused) LNG import terminals as export terminals, which would boost demand. So far, only one project – Cheniere Energy's Sabine Pass – has obtained the requisite approvals from the US Department of Energy (DOE). However, a long-awaited, DOE-commissioned study concluded that allowing US LNG exports has a net economic benefit on the economy under any scenario, and four US-based projects have already signed contracts (Figure 28).

Figure 28: US LNG export contracts by year and project (Bcfd)



Source: Bloomberg New Energy Finance, Poten & Partners Note: 1Bcfd = 7.5MMtpa

SECTION 4. LARGE-SCALE RENEWABLE ENERGY

Utility-scale projects have comprised the lion's share of new renewable generating capacity in recent years. Declining capital costs, along with federal and state incentives, have driven a boom in new development. Plummeting equipment costs, coupled with the prospect of expiring incentives, drove record-high new installations in 2012 in the wind (13.7GW) and solar (3.2GW) sectors. Another sector, hydropower, already constitutes a substantial part of the US energy mix and offers flexibility-related benefits to help the grid absorb more intermittent resources.

This section begins with an overview of policies for US renewables overall. More specific discussion of policies specific to each sector follows.

4.1. Policy for all renewables

At the federal level, tax credits, other tax benefits, and associated stimulus programs, along with significant cost reductions, have been drivers of growth in renewables over the past five years (Table 2). Most notable has been the Production Tax Credit (PTC) which has been used to subsidize sectors such as wind, biomass, geothermal, and hydropower. For wind, the PTC helped the sector deploy a record 13.7GW in 2012, by allowing qualifying projects to defray from their annual tax bill $22 for each megawatt-hour of power they generate each year over the first decade of their operating life. In the case of hydropower, 24 projects – all involving upgrades to existing facilities – received certification in 2012 to earn PTCs (hydropower receives $11/MWh, or half the credit that wind receives).

In contrast to the PTC, which is production-based, the Investment Tax Credit (ITC) allows project developers to take a tax credit equal to 30% of the cost of constructing their project. The solar industry has been the primary beneficiary of this incentive.

Table 2: Tax incentives for US sustainable energy

Tax incentive	Incentive	Sector	Expiration
Investment Tax Credit	Credit equal to 30% of eligible capital expenditure	Solar, fuel cells, small wind	Must commission by end-2016 for 30% incentive (10% incentive thereafter, without expiration)
		Wind, biomass, geothermal, hydropower, marine, tidal	End-2013
	Credit equal to 10% of eligible capital expenditure	Geothermal	No expiration
		CHP	End-2016
Production Tax Credit	Ten-year production-based credit equal to $22/MWh (inflation adjusted)	Wind, closed-loop biomass, geothermal, solar	Must 'begin construction' by end-2013
	10-year production-based credit equal to $11/MWh (inflation adjusted)	Open-loop biomass, landfill gas, trash combustion, marine, qualified hydropower and hydrokinetic	Must 'begin construction' by end-2013
MACRS	Allows tangible property to be depreciated on an accelerated basis (wind, solar and geothermal are depreciated as five-year property and biomass as seven-year property)	All sectors	Superbonus depreciation (100% in year one) expired at end-2011; bonus depreciation (50% in year one) expires in end-2013. MACRS does not expire.

Source: Bloomberg New Energy Finance Note: Small wind refers to projects 100kW or less. MACRs stands for Modified Accelerated Cost Recovery System.

These tax credits are truly the lifeblood of the renewables industry as they allow renewable energy technologies to be more cost competitive with other sources of generation. Thus any potential expiration of these credits inevitably unsettles the industry. For instance, when the PTC was due to expire at the end of 2012, wind developers rushed to get their projects generating by midnight on 31 December to ensure they received the benefit of the credit. On 1 January 2013 Congress extended the credit an additional year and changed the qualifications so that projects merely need to be *under construction* by 31 December 2013 to receive the benefit of the PTC. This critical adjustment means the benefit of this latest 'one-year' extension will be felt well into 2014 and potentially into 2015.

For its part, the 30% ITC is on the books in the US through the end of 2013 for wind, biomass, geothermal, hydropower, marine and tidal energy, and through 2016 for solar, fuel cells, and small wind (ie, <100kW). In the case of all renewables, the federal government allows project owners to use accelerated depreciation accounting to reduce their tax bills as well.

What these federal subsidies have in common is that they rely on the tax code to succeed and they are only useful to companies which need to pay meaningful amounts of taxes on income generated annually. That is often not the case for renewable energy project developers, however. Thus the sector has traditionally relied on investment from outside 'tax equity' investors (primarily banks) to provide capital in return for receiving the pass-through benefit of the tax credits. The financial crisis of 2008 squeezed availability of tax equity; a potentially calamitous situation for the industry was averted by the 'cash grant' program established under the American Recovery and Reinvestment Act (ARRA). The program temporarily allowed renewable project developers to take the value of tax credits in the form of cash payments instead. The Act also created the DOE loan guarantee program, which guaranteed $16.1bn of loans for projects and manufacturers. These programs were critical for US renewable growth in the post-crisis period; the window for qualifying for them has since closed.

Support for renewables at the federal level has had its dramatic ups and downs over the past five years. At the state level, however, support has been more consistent with policy-makers, including governors from both parties, taking a longer view in their support for the sector. No less than 29 states (plus Washington DC and Puerto Rico) have renewable portfolio standards (RPS) on their books, mandating that specific amounts of clean energy be consumed each year. Like the PTC and ITC, these RPS have been critical to growing wind, solar, geothermal, biomass, and other renewables capacity.

In fact, these mandates have been so successful in motivating clean energy development that, for most states, the targets for the next several years are on pace to be safely met, according to Bloomberg New Energy Finance's analysis of these markets (Table 3). The targets continue to escalate each year for most RPS programs, meaning that more renewable capacity will eventually need to be added to continue to stay on pace with the targets. Still, state-level RPS are not nearly as potent policy drivers as they once were, and for states to continue to see the rates of growth achieved over the past five years, some may have to raise their clean energy targets.

Table 3: Supply-demand balance of selected 'Class I' RPS programs, grouped by region

Region	Representative states with RPS	High-level evaluation of supply-demand balance
California	CA	Large utilities have contracted enough renewable capacity to meet targets through 2020 (though portion of contracted capacity may not materialize)
PJM	IL, MD, NJ, OH, PA	Both of these regions have enough renewable capacity to meet targets through at least mid-decade
Midwest	IA, MN, MO	
New England	CT, MA, ME, NH	Balance is tight, with current assessments showing overall renewable generation is slightly short of regional demand

Region	Representative states with RPS	High-level evaluation of supply-demand balance
New York	NY	Shortage, with more renewable capacity needed to be contracted to meet 2015 target
Texas	TX	Enough capacity (12GW wind) to meet even long-term goal (10GW by 205)
West US	CO, NM, OR, WA	Region overall has enough renewable capacity to meet near-term targets

Source: Bloomberg New Energy Finance Note: Analysis of supply-demand balance assumes current policy; naturally, this balance will change if RPS targets are adjusted. RPS programs are enacted and administered at the state level, but the supply-demand balance here is shown at the regional level; this is because many states allow their RPS to be met through credits generated in neighboring states. Regions denoted above roughly correspond to the territories covered by specific renewable energy credit tracking systems. 'Class I' generally refers to the portion of REC markets that can be served by a variety of renewable technologies, including wind. In contrast, SREC markets are not Class I, as these can only be met through solar. The 'Class I' component is usually the bulk of most states' renewable portfolio standards.

4.2. Large-scale solar (PV, CSP)

Policy

Policies for supporting solar in the US include federal tax credits and a variety of federal, state and utility initiatives. The most important federal incentive is the 30% ITC (explained above). At the state level, as part of their RPS program, 22 states include 'carve-outs' for solar or for distributed generation more broadly. This includes most states in the Mid-Atlantic region.

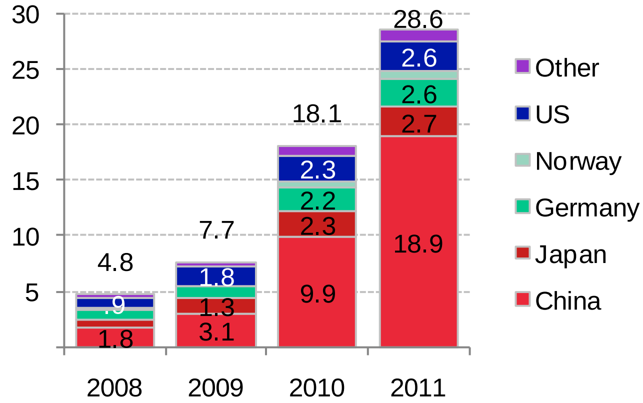
The federal and state governments also support solar build-out through specific technology, financing or procurement programs. These include the now-expired US DOE loan guarantee program: of the $16.1bn in loan guarantees issued for renewable energy generation and manufacturing, 37% was allocated to concentrated solar power (CSP) projects and 38% to photovoltaic (PV) projects (an additional 8% went to PV manufacturing). Many of these large-scale solar projects are expected to go online in the next four years.

Support for the US solar industry extends beyond incentivizing demand. The federal government has also ruled on trade laws penalizing foreign manufacturers for anti-competitive behaviour. In November 2012, the US International Trade Commission ruled that domestic PV cell manufacturers were harmed by competitors in China, upholding the anti-dumping and countervailing duties imposed by the US Department of Commerce on Chinese-manufactured cells.

Deployment

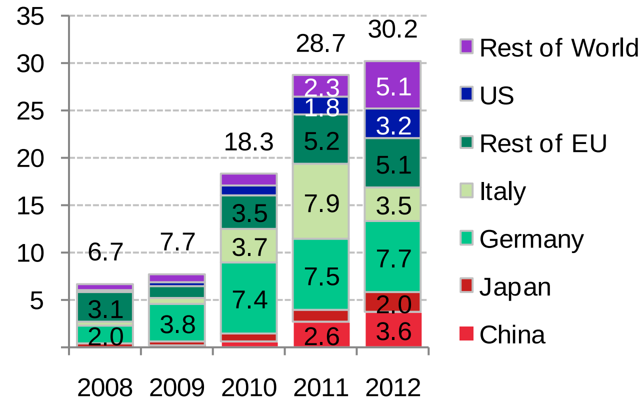
Solar manufacturers are facing massive overcapacity. There is 55-56GW of cell and module manufacturing capacity globally, but not all of that capacity is utilized; about 38GW was likely manufactured in 2012 compared with global demand for PV modules of 28.3-32.1GW (Figure 29). Oversupply is expected to continue for the foreseeable future. PV manufacturing in the US has been hit especially hard. Domestic module manufacturers' market share fell from 23% in 2009 to 9% in 2011, partly due to price competition from overseas.

Figure 29: Global PV module production by country, 2008-11 (GW)



Source: Bloomberg New Energy Finance

Figure 30: Global PV demand by country, 2008-12 (GW)



Source: Bloomberg New Energy Finance Note: 2012 figures are an estimate, based on a range between 28.3GW and 32.1GW.

Oversupply on the manufacturing side has been a boon for developers, as it has contributed to lower equipment costs. US solar project development has been solid: in 2012, large-scale PV grew by 1.6GW as many projects which had qualified for the cash grant award in 2011 achieved commercial operation (Figure 31). Much of this growth has occurred in California, where several incentives support development of large-scale PV; approximately 350MW of utility-scale PV projects were installed in that state in 2012.

In recent years, a category of PV projects known as 'wholesale distributed generation' has flourished. These projects, in the 1-30MW range, are utility-sided (rather than behind-the-meter) installations which have the virtue of being interconnected to the distribution grid, precluding the need for new transmission lines, which tend to involve long lead times and frequently encounter permitting obstructions. Development of these projects has been spread across the country. Examples include Juwi Solar's 12MW Wyandot plant in Ohio (with American Electric Power as the offtaker), Lincoln Renewable Energy's 12.5MW Oak Solar plant in New Jersey (with Macquarie Energy providing project finance as part of the PPA), and SunEdison's 30MW Webberville plant in Texas (with Austin Energy as the offtaker).

In the case of CSP generation, construction is underway for five very large plants, all recipients of DOE loan guarantees, totalling 1.3GW. Most are expected to come online in 2013. Their successful construction and operation will mark an important milestone for an industry keen to demonstrate that it can deliver projects on a large scale. CSP is also having to defend itself against the rapidly improving economics of PV; a raft of projects which had initially been proposed as CSP installations have now been re-permitted and transformed into opportunities for PV development.

Figure 31: US utility-scale PV build, 2008-12

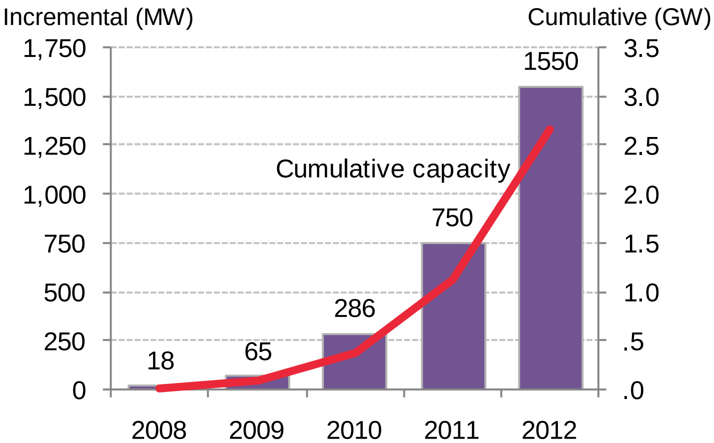
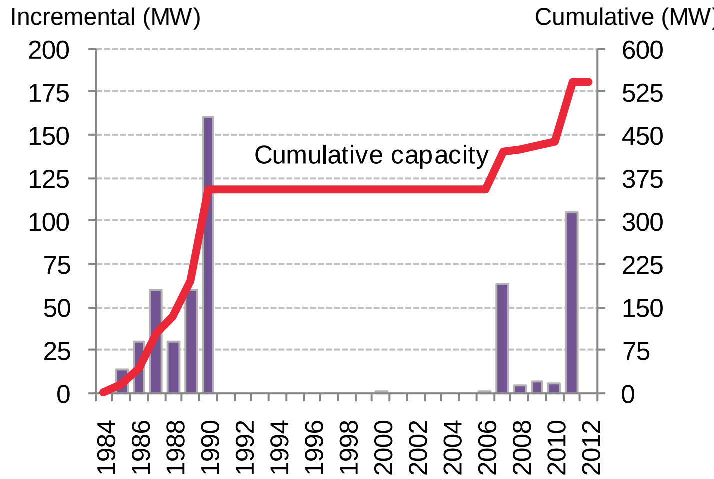


Figure 32: US CSP build, 1984–2012



Source: Bloomberg New Energy Finance Note: California Energy Commission provides resources to track developments of large CSP plants in the state: http://www.energy.ca.gov/siting/solar/index.html

Financing

Investments in thin-film technologies accounted for the sizable deployment of private equity expansion capital in 2008 (Figure 33). Since then, investment activity in thin-film has declined. More recently, venture capital in the services and support sector, such as third-party financing business models, has grown. In the case of asset financing, investment volumes in 2011 were unusually high, buoyed by the DOE loan guarantee program. Nevertheless, even without incentives available in 2011, the 2012 numbers, at $7.5bn, are evidence that solar project deployment continues to gain momentum.

Figure 33: Venture capital / private equity investment in US solar by type, 2008-12 ($bn)

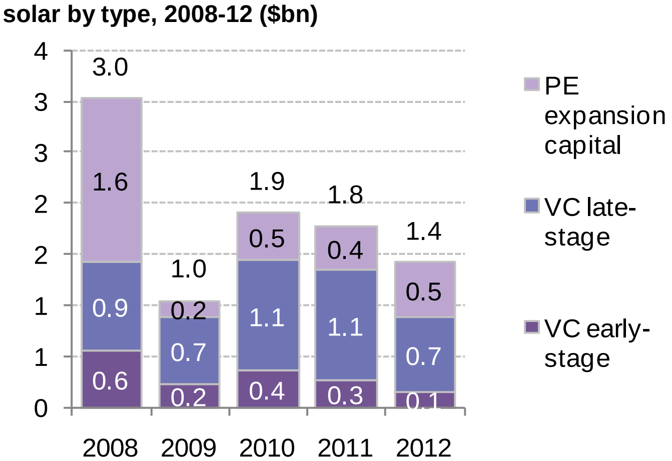
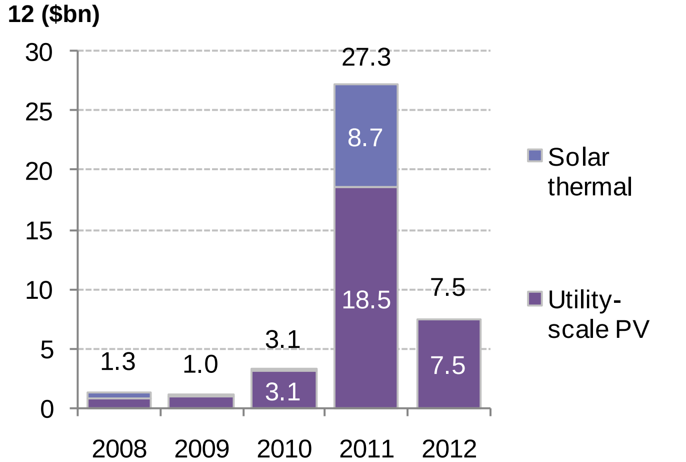


Figure 34: Asset finance for US solar projects by type, 2008-12 ($bn)

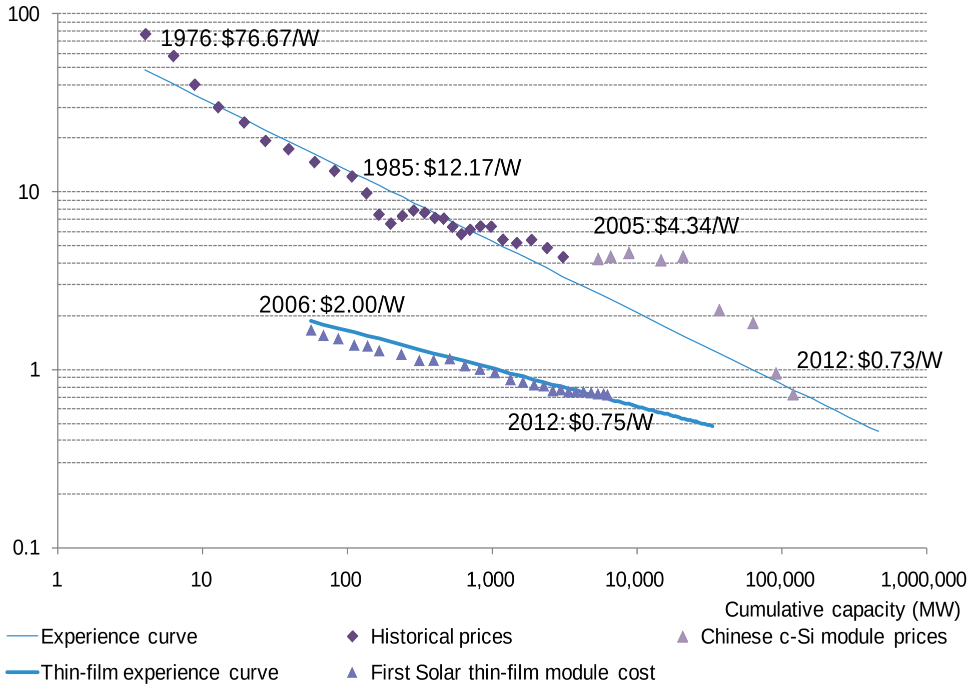


Source: Bloomberg New Energy Finance Note: Only includes electric generating assets. Does not include solar thermal water heaters. Values include estimates for undisclosed deals.

Economics

Crystalline silicon (c-Si) module prices have declined 99% since 1976 (Figure 35). More recently, oversupply has driven down current global average spot prices to $0.79/W, below the marginal costs of producing most modules. Large developers are able to obtain a discount and are buying panels at an average price of about $0.73/W. The recent duties imposed on Chinese-manufactured cells have had little effect on the pricing of modules in the US market as most Chinese players have shifted cell manufacturing to Southeast Asia.

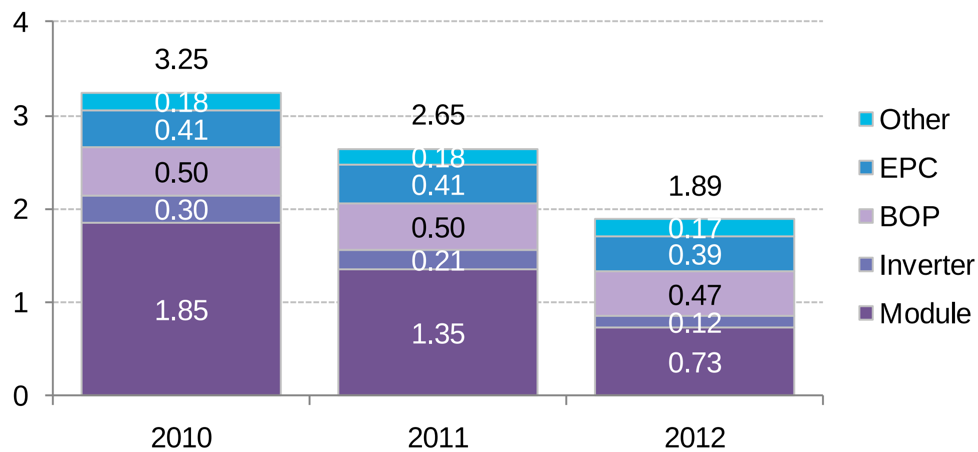
Figure 35: Capex – price of c-Si PV modules, 1976–2012 ($/W)



Source: Bloomberg New Energy Finance, Paul Maycock, company filings Note: Prices in 2011 USD.

The module price decline has helped drive down average global best-in-class utility-scale system costs to $1.89/W (Figure 36). Inverter prices also sank in 2012. Quotes for engineering, procurement and construction (EPC) for large systems continue to fall as well.

Figure 36: Capex – best-in-class cost of global utility-scale PV, 2010-12, ($/W)



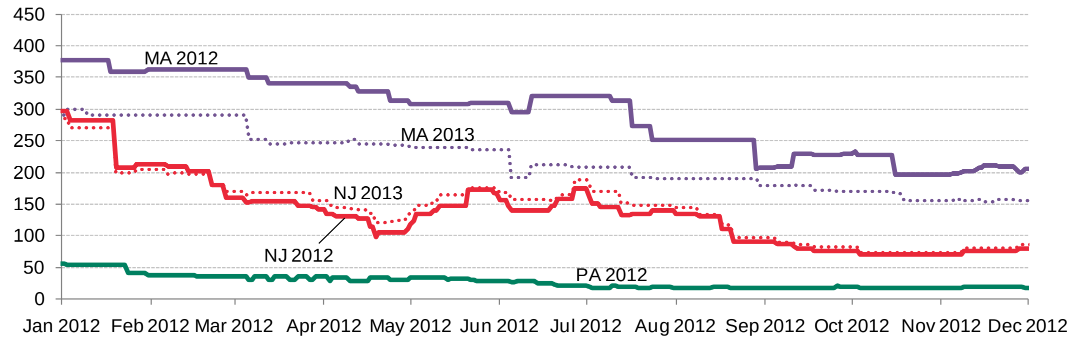
Source: Bloomberg New Energy Finance

Large-scale power projects, including solar ones, must contract an offtaker for their energy to gain future revenue certainty and achieve bankability. These contracts are called power purchase agreements (PPAs). Bloomberg New Energy Finance collected PPA data for 17 utility-scale solar projects located primarily in the Desert Southwest, revealing pricing mostly in the $120–160/MWh range. These projects signed PPAs between late 2008 and mid-2011. Intense competition for solar PPAs, along with declining system costs, have since caused solar PPA rates to plummet. California auctions held in 2011 for projects looking to deliver power in 2016 yielded prices in the $70–90/MWh range.

Along with the revenues captured from the sale of electricity through a PPA, solar projects in some parts of the country receive a separate revenue stream associated with the sale of solar renewable energy credits (SRECs). These SRECs represent the environmental attribute of the generated electricity. Utilities procure SRECs to achieve compliance with the solar carve-out programs of a state RPS.

SREC prices have been on the decline in many markets as a result of oversupply – ie, more solar power was generated than was required under the year's target (Figure 37).

Figure 37: Solar REC prices in selected states' markets, 2012 ($/MWh)



Source: Bloomberg New Energy Finance, Evolution Markets, Spectron Group, Karbone Note: Year refers to the vintage of the SREC.

In some cases, solar PV systems are being installed below $2.50/W, because of declining module prices, tightening developer margins, reduced installation fees, and equity investors reportedly willing to accept lower returns to keep projects alive. Due to this belt-tightening, projects can still be built at SREC prices much lower than market prices prevalent in 2011.

Market dynamics

Solar companies in the US that have previously focused on the upstream are tending to vertically integrate their operations to capture the higher-margin business of utility-scale solar project development and to ensure market demand for their products. Three of the largest US-based solar companies are First Solar, SunPower, and MEMC. These entities now operate as manufacturer-developers, wherein they both manufacture solar components and use these components for projects that they have developed. The large-scale solar market also has a large number of independent power producers (IPPs), developing solar projects and then selling the asset to investors, energy companies, or utilities.

4.3. Wind

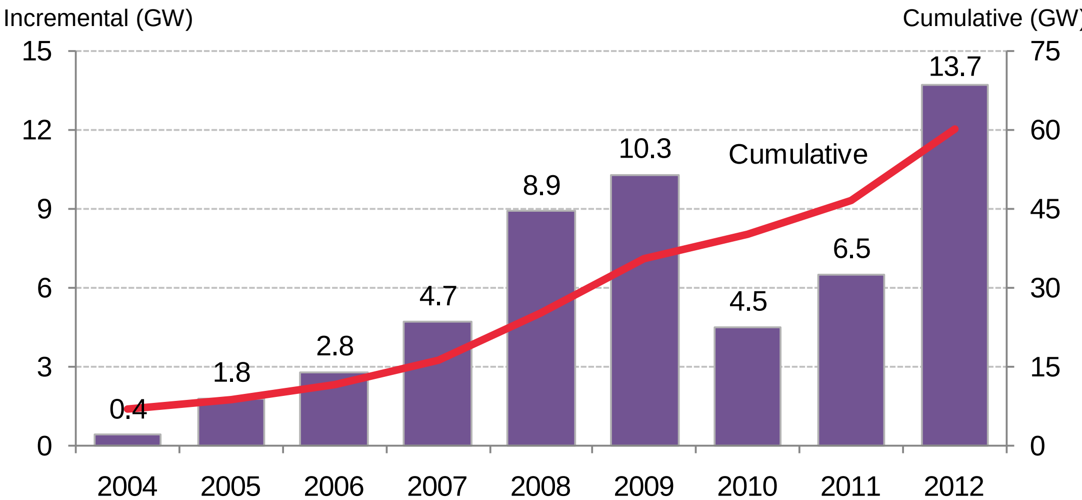
Policy

The major federal subsidy for wind energy in the US was the PTC, which was due to expire at the end of 2012 but which was extended on 1 January 2013 for an additional year and with an important adjustment that will allow it to have market impact well into 2014. The incentive provided an income tax credit of roughly $22/MWh (indexed for inflation) for electricity generation for the first 10 years of the project's life. Other major policy support from wind energy exists on the state level through RPS programs (explained above).

Deployment

2012 was a record year for wind build in the US with 13.7GW of capacity commissioned (Figure 38). The previous record year for wind build was 2009 – a delayed result of the easy financings, high power prices, and heady load forecasts from before the financial crisis. By contrast, 2010 was the first year the effects of the financial crisis were evident as installations fell by over 50% due to financing scarcity. In 2012, the spike in new build was prompted by uncertainty over the possible expiration of the PTC; many utilities moved forward procurement plans to take advantage of the subsidized energy in anticipation of its potential end. More broadly, the sector has grown thanks to the decline in the cost of wind energy; with the help of incentives, this has led to extremely cheap long-term power contracts in states such as Oklahoma and Kansas.

Figure 38: US wind build – annual (2004-12) and cumulative (GW)



Source: Bloomberg New Energy Finance

The availability of wind manufacturing capacity peaked in 2012 (Figure 39). Alstom, Gamesa, GE, Nordex, Siemens, Clipper, Vestas, and Mitsubishi all received tax credits for building manufacturing facilities in the US, resulting in a surge in turbine supply and significant overcapacity, which eventually contributed to declines in turbine prices. At least two of those facilities (Alstom and Mitsubishi's) are believed to have been mothballed shortly after completion. Other manufacturers, including Gamesa, Vestas, Siemens, and Clipper, have announced capacity reductions through workforce lay-offs, reflecting an industry struggling from insufficient demand to absorb capacity (Figure 40).

Figure 39: Wind turbine production capacity on US soil by manufacturer, 2008-12 (GW)

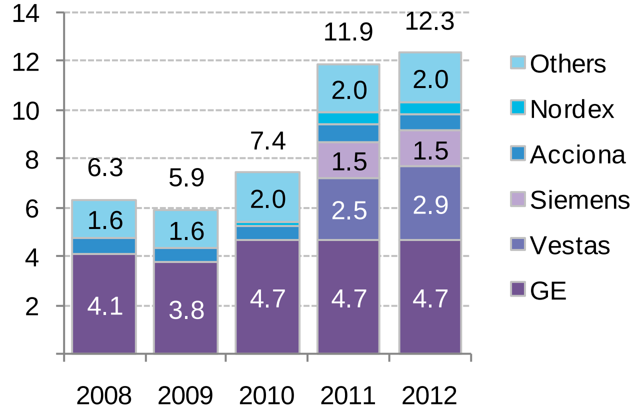
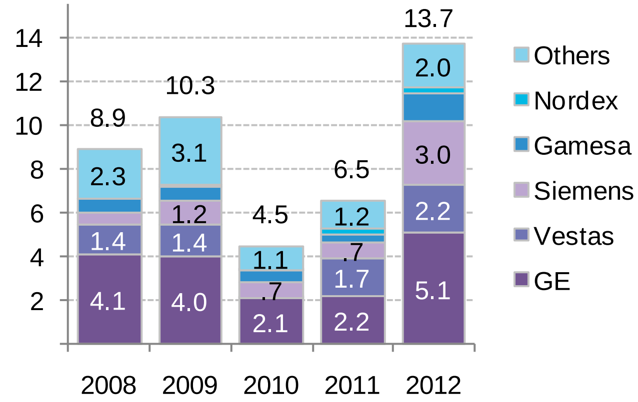


Figure 40: Wind turbine supply contracts for financed US projects by delivery year, by manufacturer, 2008-12 (GW)

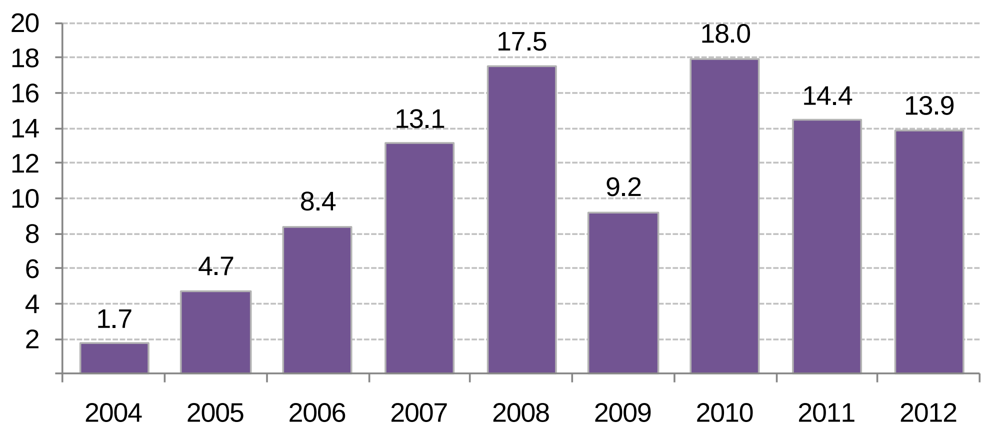


Source: Bloomberg New Energy Finance

Financing

Asset finance volume in 2012 for new wind projects totalled $13.9bn, nearly matching the $14.4bn closed in 2011 (Figure 41). In prior years, annual asset financing acted as a leading indicator for the following year's new build. In 2012, however, nearly all of this type of investment was for projects scheduled for delivery that same year. Just 300MW of capacity for delivery in 2013 was financed in 2012 foreshadowing a difficult year for US wind.

Figure 41: Asset finance for US wind projects, 2004-12 ($bn)

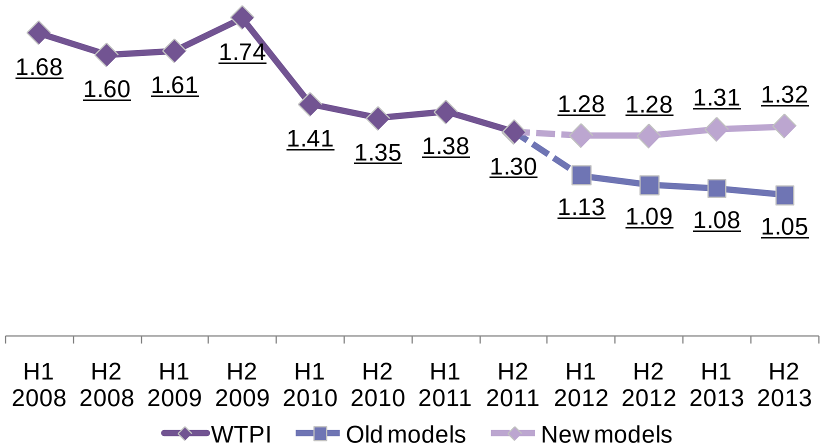


Source: Bloomberg New Energy Finance Note: Values include estimates for undisclosed deals.

Economics

Global turbine prices declined by roughly 40% over 2009-12 (Figure 42). Keeping all other cost components equal, a 40% decline in turbine prices equates to a roughly 22% decline in the levelized cost of electricity (LCOE) for wind. Turbine performance has also improved, particularly for those purposed for low wind speeds. A 5% improvement in capacity factor, from an average of 30% to an average of 35%, drives down the LCOE of wind by roughly 13%. The combined effect of a 40% decline in turbine prices and a 5% improvement in capacity factor yields more than a 30% decline in the average LCOE of wind energy.

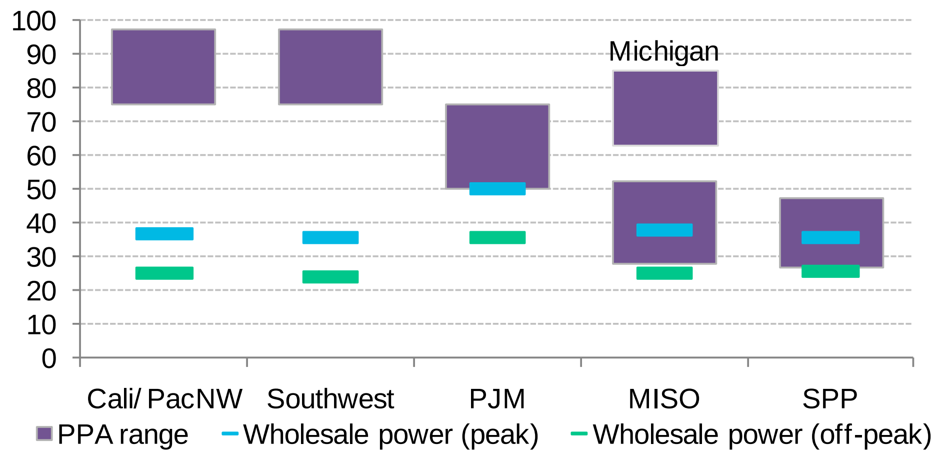
Figure 42: Capex – wind turbine price index by turbine type and delivery date, 2008-12 ($m/MW)



Source: Bloomberg New Energy Finance Notes: Global Wind Turbine Price Index converted to from EUR to USD by the average EUR/USD rate for the half year of turbine delivery.

Pricing for PPAs has reflected these radically improving economics. Pricing in Michigan, for example, is reported to have dropped from the mid-nineties in 2011 to the mid-sixties in 2012. In North Dakota, Kansas, and Oklahoma, PPA prices in 2012 were recorded in the low $30/MWh range, and at least one contract was priced below $30/MWh (Figure 43). These prices were contingent on the PTC. Without a federal subsidy, pricing on these contracts would likely have been in the mid-fifties.

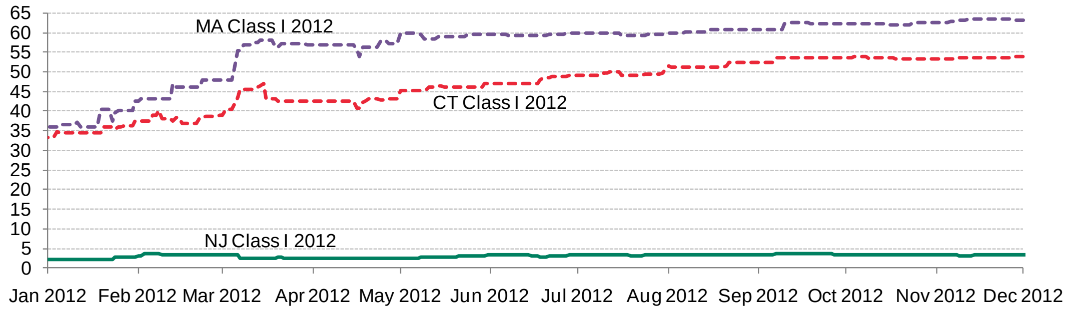
Figure 43: PPA prices for select US wind markets ($/MWh)



Source: Bloomberg New Energy Finance, Federal Energy Regulatory Commission, SEC filings, analyst estimates Notes: 'Cali/PacNW' refers to the wind market in California and the Pacific Northwest; 'Southwest' refers to markets in the southwest US; 'PJM' refers to the Mid-Atlantic market; 'MISO' refers to the Midwest; and 'SPP' is the Southwest Power Pool, covering the central southern US.

Due to the cheap price of wind PPAs, some utilities signed contracts above their RPS targets. As a result, REC prices collapsed in key markets. Figure 44 demonstrates that NJ Class I RECs (representative of the Mid-Atlantic market) are sitting near a price floor. In contrast, New England's REC market is tight – and credit prices are high – as difficulties with project permitting make it burdensome for new supply to enter the market.

Figure 44: 'Class I' REC prices in selected markets, 2012 ($/MWh)



Source: Bloomberg New Energy Finance, Evolution Markets, Spectron Group, Karbone Note: 'Class I' generally refers to the portion of REC markets that can be served by a variety of renewables, including wind. In contrast, SREC markets are not Class I, as these can only be met through solar. The 'Class I' component is usually the bulk of most states' renewable portfolio standards.

Market dynamics

Top wind asset owners in the US in 2012 included NextEra, Iberdrola, EDP, and MidAmerican Energy (Figure 45). Until 2009, some wind projects developed by the unregulated subsidiaries of large utilities were built without long-term offtake agreements – ie, on a merchant basis. With the collapse in electricity prices, these utilities and other developers with merchant exposure have reduced their merchant capacity by signing PPAs and are no longer building projects without a long-term contract. Caithness and Terra-Gen, along with developers like Pattern Energy and First Wind, are large developers with a substantial development record, but without the balance sheet of the large utilities. These developers rely on third-party project finance to start construction.

Apart from these major US players, there are hundreds of smaller developers. Most focus on developing in a few regions and look to bring projects through early stage development then selling them to larger developers or asset owners for final construction. Proceeds from the sale of equity in either commissioned or close to commissioned projects are reinvested in other development assets.

Figure 45: Top 10 US wind owners, as of year-end 2012 (MW)

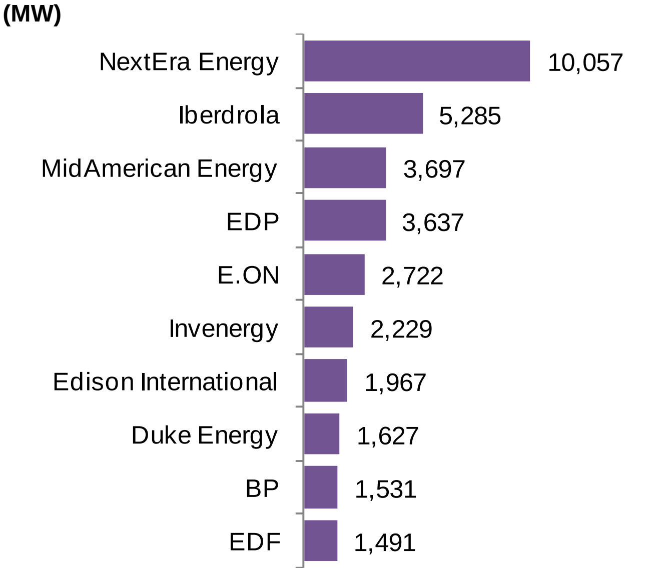
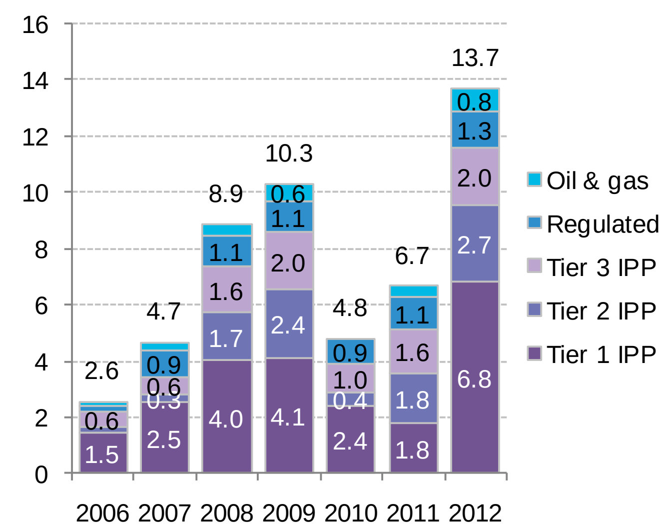


Figure 46: US wind capacity commissioned or under construction by type of developer, 2006-12 (MW)



Source: Bloomberg New Energy Finance Notes: In Figure 45, ownership is based on 'net ownership' as opposed to 'gross ownership', to account for co-ownership. Values are based primarily on data directly from company websites. In Figure 46, 'Tier 1 IPP' refers to large and experienced US developers capable of financing project on the balance sheet, without external financing; 'Tier 2' refers to experienced developers that are not *capable of constructing projects without external financing. 'Tier 3 IPPs' refer to smaller and less-experienced developers.*

4.4. Biomass and waste

Policy

In general, federal policies support biomass and municipal solid waste (MSW) feedstock development, while state legislation drives market demand via RPS programs. The federal government also provides a critical incentive in the form of the PTC, valued at $11/MWh and available through the end of 2013, for electricity derived from biomass and waste.

Biomass

The federal government has in place a set of programs aiming to incentivize biomass power generation. Most target development of sustainable biomass and conversion technologies. However, these initiatives have seen their fund allocation drop significantly in the past two years.

The Department of Agriculture's (USDA) flagship support mechanism is the Biomass Crop Assistance Program (BCAP), which offers direct subsidies for new energy crops. The program offers dollar-to-dollar matching payments to cover biomass delivery costs (collection, harvest, storage and transport) of up to $50 per tonne. It also offers support of up to 75% of total new crop establishment cost to projects developing non-woody and woody perennial biomass crops. Funding for the program in 2008–11 reached $440m; in 2012, only $17m was made available. Funding for BCAP has not been extended for 2013.

MSW

Waste-to-energy projects are currently supported by the Energy Policy Act (2005), Energy Independence and Security Act (2007) and the American Recovery and Reinvestment Act (2009). State government efforts to legislate against interstate MSW movement offer further encouragement to the waste-to-energy industry. Recent supportive US recycling legislation will increase the competition for the paper and paperboard fraction of MSW.

Deployment

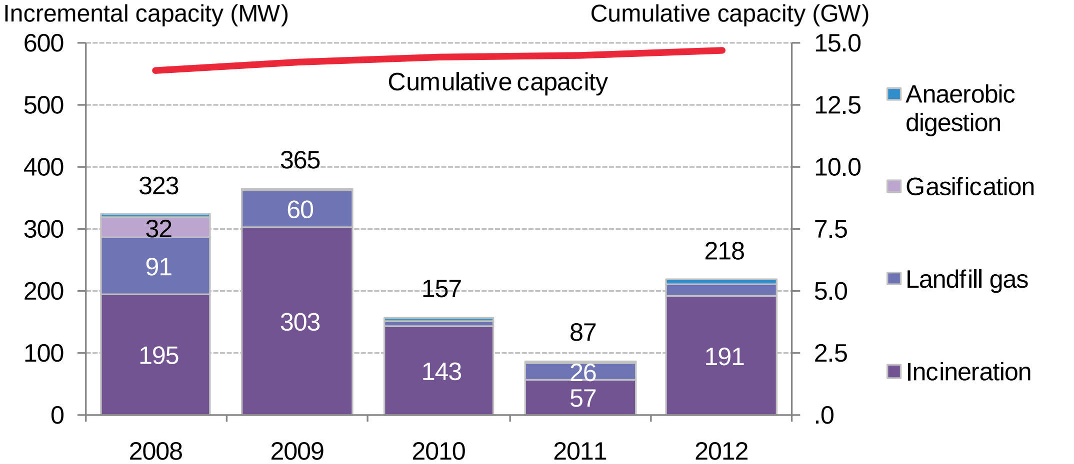
Biomass

Since 2008, interest in dedicated biomass combustion has started to pick up, driven by attractive state subsidies or feedstock availability.

MSW

The US currently only recovers 13% of its waste energy content – compared with northern European countries that recover approximately 40% on average. The last 15 years have been problematic for the US waste-to-energy industry. The number of waste-to-energy plants has decreased substantially from roughly 180 facilities in the 1980s to about 90 today. Tax law changes, new landfill site development, low tipping fees and the introduction of Maximum Achievable Control Technology (MACT) standards have caused considerable industry disruptions. However, there are now some signs of renewed interest. The majority of waste-to-energy facilities are located in the northeast US, where the landfill fees are the highest and surpass the incineration gate fees (the cost a MSW facility charges per ton of waste received).

Figure 47: US biomass and waste project build by type – annual (2008-12) and cumulative



Source: Bloomberg New Energy Finance

Financing

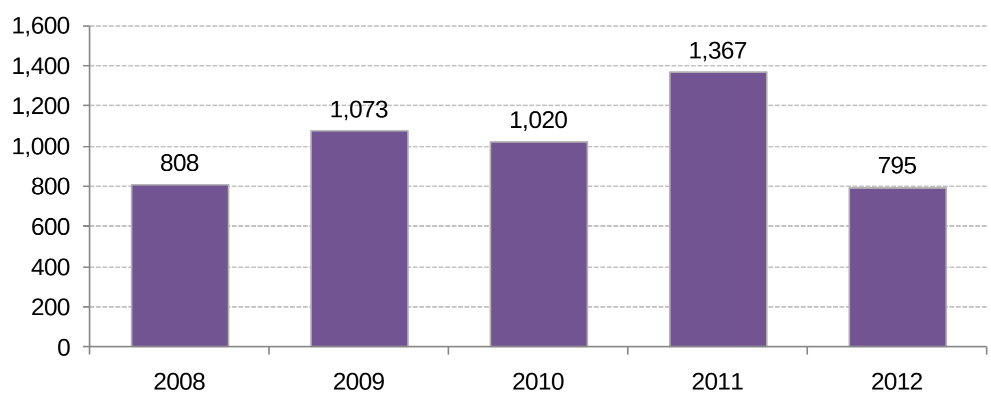
Biomass

Annual asset finance for biomass generation averaged just over $900m from 2008-12 (Figure 48). This is substantially lower than in the wind and solar sectors, due to the smaller number of bankable projects. Capital tends to be available for biomass projects that have in place PPA, an experienced engineering, procurement and construction contractor and some protection against feedstock availability and price risk.

MSW

The US waste-to-energy sector is small and investment opportunities are scarce. Since 2008 Bloomberg New Energy Finance has recorded just two asset finance deals: a $302m project in Hawaii developed by HPower and a $10.5m project in Sacramento developed by Clean World Partners.

Figure 48: Asset finance for US biomass and waste projects, 2008-12 ($m)



Source: Bloomberg New Energy Finance Note: Values include estimates for undisclosed deals.

Economics

Biomass

Project economics are driven by capital expenditures (capex), which decrease (on a $/MW basis) with scale, and by feedstock costs, which tend to rise with scale.

Capex for biomass combustion varies depending on project size, and whether it is a retrofit. Figure 49 presents benchmark estimates. Small dedicated biomass combustion plants of less than 10MW, whether producing electricity or both heat and electricity, have the highest capex – up to $5m/MW. Projects between 30MW and 200MW have a range of $1-3m/MW. Coal-fired power stations converted into biomass plants have lower capex, with an average of $0.68m/MW. Adding enhanced co-firing capacity to a coal power plant can also be an inexpensive way of burning biomass, at $0.2m/MW, assuming the coal capex has already been paid off.

In terms of feedstock, despite ample land availability for biomass cultivation, the US relies heavily on biomass from Canada. As a result of a strong Canadian dollar, US generators are now looking for non-wood biomass feedstock elsewhere. And because US fossil fuel-generated electricity is cheaper than in Europe, margins have been further squeezed, making rising feedstock costs a major concern for US combustion plant operators.

MSW

In general, gate fees (the costs of waste received by the generator) for combustion are higher than for landfilling. The average incineration gate fee in the US is about $66/tonne – roughly 37% higher than average landfill gate fees in the US. This is not conducive to the development of more combustion plants as the penalty for combusting a tonne of MSW is greater. Therefore, the rate of new build is falling.

Figure 49: Capex – capital costs for biomass and waste projects by type, 2008-12 ($m/MW)

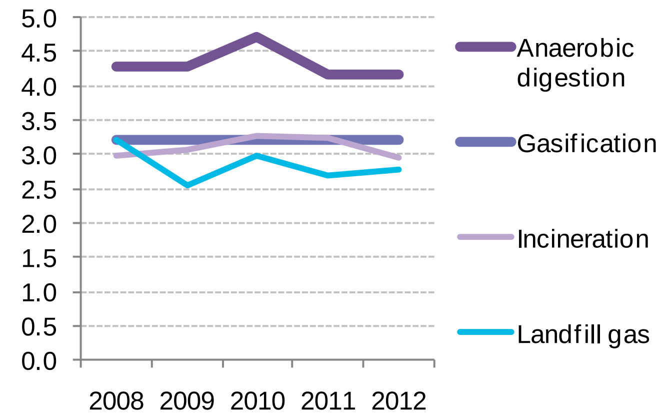
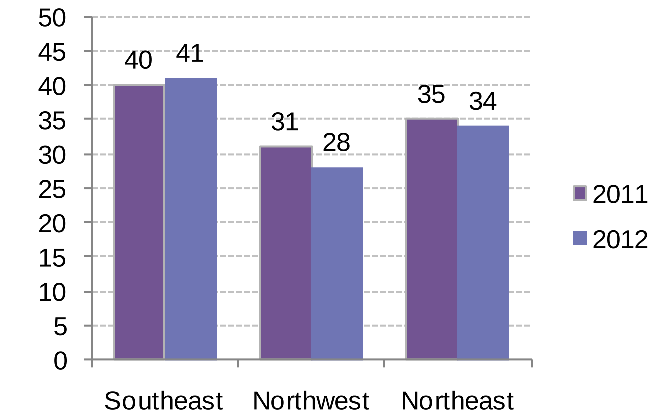


Figure 50: Woody biomass feedstock prices in selected markets, 2011-12 ($/dry ton)



Source: Bloomberg New Energy Finance Note: Feedstock prices are highly regional and may vary depending on local supply.

Market dynamics

Biomass

Unlike most renewable technologies, variable costs – especially those associated with the feedstock – make up a significant portion of a biomass plant's levelized cost of energy. Operators of biomass plants face an ongoing decision: are the marginal revenues – in the form of sales of electricity plus RECs – sufficient to overcome the significant marginal costs?

In New England, where biomass has been an especially important source of renewable energy, the answer to this question has been effectively 'no' for much of the past two years. Many biomass plants there have temporarily or permanently halted production in the face of new regulation and depressed power prices at a time of cheap natural gas, though high REC prices in the region over the past year have offered a welcome reprieve. Large players in this region include ReEnergy, GDF Suez, and Covanta.

MSW

The main barriers obstructing more investment are: a lack of strong legislation limiting landfilling activity; low landfill tipping fees; poor waste management practices in states where there was capacity stress; rather low energy prices; and low public acceptance for waste-to-energy projects. It has historically therefore been difficult for waste-to-energy technologies to compete with landfill sites. However, major urban areas in the US have run out of nearby landfill space. Regulations in some states have imposed a fine on recycled waste being transported to other states for burial. This leaves the US with large amounts of MSW, which is becoming more expensive to landfill as gate fees increase.

Covanta is among the most significant players in the US waste-to-energy industry. The company operates 40 waste-to-energy facilities in the US totalling around 1.5GW nameplate capacity. It processes around 19m tons annually, equivalent to 5% of the country's waste. Another significant player is Waste Management, which operates 17 plants through its subsidiary Wheelabrator Technologies. Its plants have a combined capacity of 670MW and process 9m tons of MSW annually. Waste Management has also invested in Harvest Power, an anaerobic digestion company, which is active in renewable energy production and organic recycling. Wheelabrator, Covanta and Advanced Disposal Services (which in 2012 acquired Veolia's solid waste business in the US) operate more than half of all the US waste-to-energy facilities.

4.5. Geothermal

Policy

Unlike other clean energy technologies, geothermal continues to benefit from the 1603 'cash grant' program established by the American Recovery and Reinvestment Act in 2009. Geothermal projects that are online by 1 January 2014 are qualified to receive a grant covering 30% of their capex. This deadline is a year later than for other sectors to account for longer geothermal project lead times. But to qualify, projects must also have initiated construction by 31 December 2011. Those that did not meet the construction initiation deadline can still receive the benefit of the $22/MWh PTC so long as they are operating by 31 December 2013. A 30% ITC is also available until the same deadline, and can be taken in lieu of the PTC. If a company with a qualifying project misses the in-service deadline, it can still obtain a 10% cash grant if it commissions the facility by 1 January 2017, or a 10% ITC which currently has no expiration.

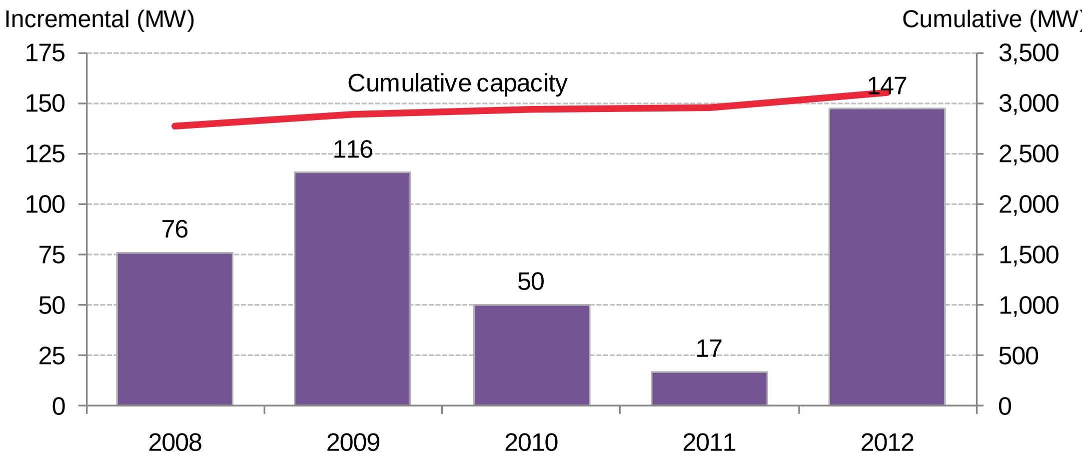
Geothermal has also benefited from state RPS programs – particularly in California and Nevada. Compared to other technologies eligible for the RPS, geothermal's ability to provide baseload power gives it a competitive advantage.

Deployment

The US geothermal sector is the largest globally, but geothermal represents just a slim part of domestic renewable energy generation and a tiny slice of the overall US portfolio. Despite the US Geological Survey pinning its most conservative estimate for US geothermal resource potential at 9GW, the sector hovers at 3GW and is struggling to put additional capacity online. Project development is difficult at all stages, as is financing, and the present policy environment only compounds matters. As a result, geothermal developers and investors are shifting focus to emerging markets such as Indonesia, Kenya and Chile. The possible ray of sunshine for the US sector, though, is Hawaii.

The 2009 stimulus helped bring 147MW online in 2012, the highest since 1990 (Figure 51).

Figure 51: US geothermal project build – annual (2008-12) and cumulative (MW)



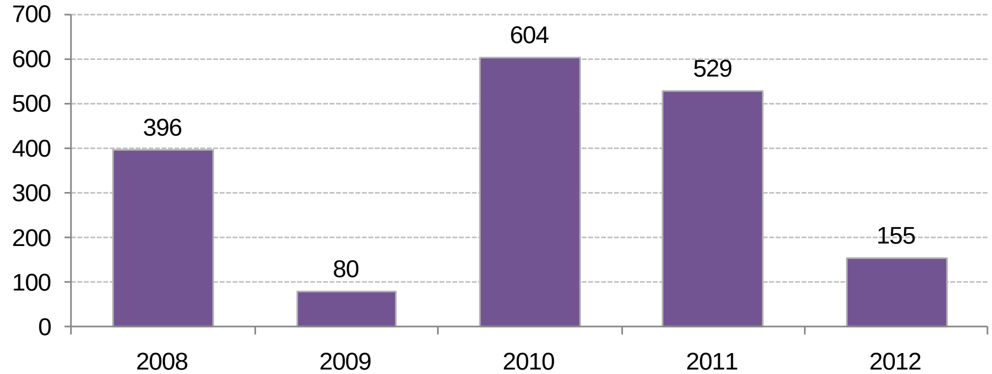
Source: Bloomberg New Energy Finance

The deployment outlook is not especially promising. Utilities would *prefer* to have more geothermal available to counter some of the reliability issues introduced to the grid via variable resources such as wind and solar, but this would require state regulators to allow utilities to hold solicitations specifically for geothermal PPAs; there are currently no plans for this. However, there is a 50MW draft request for proposals out in Hawaii, where the state is eager to move away from oil and diesel power to take advantage of its abundant geothermal resources.

Financing

On 7 December Nevada-based Gradient Resources closed on the sole construction finance transaction for the year – $155m debt from a consortium of four investors to build the 30MW Phase I of its Patua facility.

Figure 52: Asset finance for US geothermal projects, 2008-12 ($m)



Source: Bloomberg New Energy Finance Note: Values include estimates for undisclosed deals.

Vendor financing has emerged as an alternative to traditional sources of capital: developers receive financing at favourable rates, and vendors increase their odds on supply contracts. The sample size is small, almost certainly limited by lack of projects, not investor appetite. Japanese turbine manufacturer Fuji and US-based engineering firm Science Applications International Corporation (SAIC) are examples of large vendors that have helped finance projects using their equipment and services.

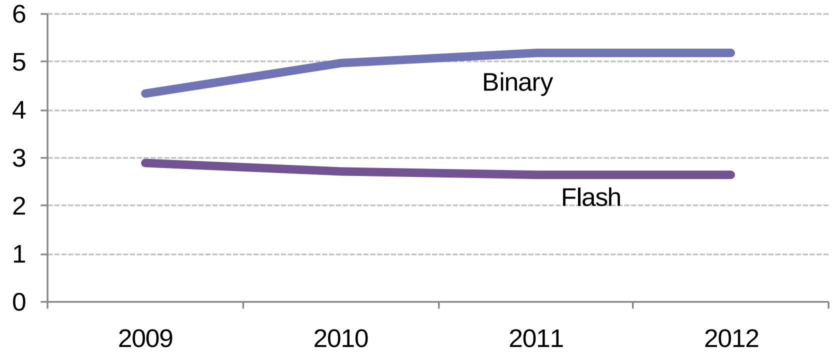
Economics

There are two main types of geothermal plant in the US being developed today – flash and binary. Flash plants operate by 'flashing' pressurized geothermal fluid delivered by wells into steam, which drives a turbine. Binary projects operate by using lower-temperature (<150º C) geothermal fluid to heat a secondary 'working fluid' with a lower boil point; this secondary fluid turns to steam and drives a turbine.

Geothermal capex averaged about $2.65m/MW for flash and $5.18m/MW for binary projects over 2008-12 (binary projects involve more process equipment and therefore can be more expensive). However, capex can vary significantly depending on site-specific factors. Averaging $63-97/MWh, the LCOE for geothermal is often near the lower end of the spectrum when compared to other renewable technologies. But high upfront costs for exploratory drilling often keeps projects stranded at the starting line and as the projects are so resource-specific, numerous additional factors hugely affect economics – eg, resource characteristics such as temperature, flow rate, and depth, as well as drill rig availability and plant cost.

For companies that can move projects forward in the current environment, the economics are actually quite favourable. Plant costs for flash are coming down, owing largely to increased competition in the turbine and EPC supply markets. In 2012, steam turbine contracts (with turnkey EPC included) averaged $1.4–1.5m/MW; by comparison, before the global financial crisis, the all-in sum averaged $2m/MW. The turbine and generator account for about 25% of the cost, with the remaining 75% going to construction and the rest of the equipment – the cuts have been largely in this latter portion.

Figure 53: Capex – capital costs for geothermal projects by type, 2008-12 ($m/MW)



Source: Bloomberg New Energy Finance

Market dynamics

Given the policy situation in the US, there was very little new project initiation in 2012. For the most part, companies with projects nearing completion are finishing them but shifting their attention to markets more favourable for new development. In this group is Ormat Technologies, which will continue to be the big fish in the US market, together with US Geothermal, Gradient Resources, EnergySource, and Enel Green Power. Lastly, project performance has been an important theme for the sector in the US, as several notable projects have performed below expectations.

4.6. Hydropower

Policy

The primary federal incentive for hydropower is the 30% ITC, which was extended for one more year as part of the 1 January 2013 tax package (projects must begin construction by the end of 2013). Developers can also choose to take an $11/MWh PTC in lieu of the ITC. On the state level, most RPS programs allow 'small hydropower' to qualify (the qualifying size of a project varies by state).

Deployment

Hydropower represents the second-largest largest source of non-fossil-fuel generation in the US, behind nuclear (7% of generation, with nuclear at 19%). Recent development has been limited – 19MW was commissioned in 2012 – compared with the cumulative installed capacity base of 79GW, or 101GW including the contribution from pumped storage projects (Figure 54).

Development in recent years has been predominantly small-scale (<100MW). Yet there is some activity to pursue large-scale build: Alaska is in the process of permitting the 600MW Susitna-Watana project, projected to come online by 2023, and the US DOE has released a report showing there are several projects larger than 100MW at existing non-powered dams and is currently in the midst of an assessment of large-scale greenfield projects across the US. In addition, Pennsylvania utility PPL is nearing completion of a $434m project to add another 125MW to its 108MW Holtwood hydropower plant.

Unlike other clean energy sectors, there is no 'one-stop shop' for annual installed hydropower capacity data. The incremental capacity figures in Figure 54 are sourced from the Federal Energy Regulatory Commission (FERC), which only provides figures from 2009. Additionally, FERC data does not include hydropower projects developed by the federal government (eg, the Army Corp of Engineers). Thus, Figure 54 may understate actual annual installed hydropower capacity.

Though recent installation numbers have been low, developers have received licenses or exemptions from FERC for 730MW of new capacity since 2009, potentially foreshadowing an upswing of new development (Figure 55). (Exempted projects do not require renewed applications to FERC to continue operating, as opposed to licenses, which have terms of 30-50 years. All hydropower projects, both licensed and exempted, require environmental reviews, public participation, and agency consultation before licenses or exemptions are permitted to proceed.)

Figure 54: US hydropower project build, 2008-12

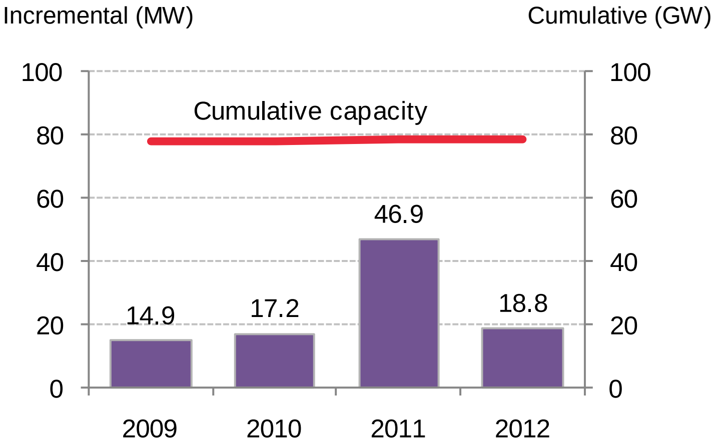
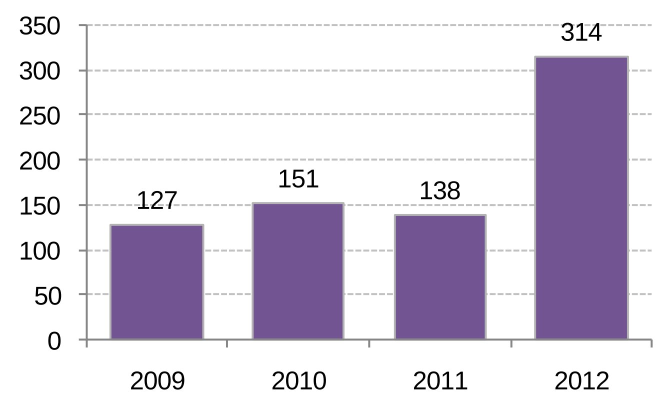


Figure 55: US new hydropower capacity licensed or exempted by FERC, 2010-12 (MW)



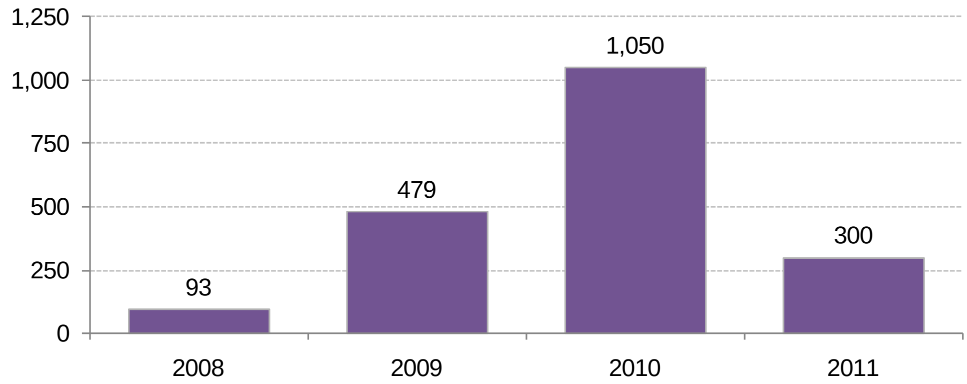
Source: Bloomberg New Energy Finance, EIA, FERC Note: Data on cumulative capacity is from the EIA; incremental capacity from FERC.

Financing

US hydropower asset finance flow has been slow compared with that for other renewable energy sectors with an estimated $1.9bn provided from 2008-11. The bulk of this is attributed to American Municipal Power, which began construction on several plants totalling 300MW of new capacity on the Ohio River in 2009-11. It estimated a total cost of $1.7bn for these new installations, implying a weighted capex of about $5.7m/MW

The relatively low volume of financing has been a function of limited development (aside from the project mentioned above) rather than a scarcity of capital. Project financiers report that financing is typically available at a reasonable cost for good hydropower projects with a credit-worthy offtaker.

Figure 56: Annual asset finance for US hydropower projects, 2008-2011 ($m)



Source: Bloomberg New Energy Finance Note: 2012 data is not available.

Economics

Project economics for hydropower plants are heavily dependent on site-specific factors, including the availability and constancy of water resources and the cost of site preparation and material procurement. Five US hydropower projects disclosed total construction costs in 2008-12, with costs ranging from $3m/MW to $6.34m/MW and an average capex of $4.57m/MW.

Market dynamics

In the world of small hydropower, the largest asset owner is Brookfield Renewable Energy Partners. As of end-2011, the company had 103 US projects in 11 states totalling 1,966MW of capacity (plus other large and small hydropower assets in Canada and Brazil). Hydro Green Energy and Free Flow Power are other examples of independent power producers targeting this sector. While IPPs are the principal players behind small hydropower, the development of large hydropower plants is generally a utility- or state-led effort. The projects tend to be rate-based, owing to the massive capital expenditure involved – ie, the 600MW Alaska project is under the direction of the Alaska Energy Authority and will require an estimated capex of $5.2bn.

Hydropower, including run-of-river projects, is a dispatchable asset, capable of providing much-needed flexibility to the grid. Yet most electricity market structures do not fully monetize the flexibility-related benefits – including the ability to help the grid absorb variable energy resources – offered by hydropower and by pumped storage (detailed further in Section 5.6 covering energy storage).

SECTION 5. DISTRIBUTED POWER, STORAGE, CCS

The US power sector – long skewed towards large, centralized systems such as coal plants – is beginning to open up to a wide range of small, distributed power generators, including combined heat and power (CHP) generators, fuel cells, and small-scale renewables. Other technologies with the potential to transform the future grid – including storage technologies other than pumped hydropower and carbon capture and storage (CCS) – are showing their earliest signs of life.

5.1. Small-scale solar

Policy

As with large-scale projects, solar carve-outs under RPS programs are a source of demand for small-scale solar. In fact, in some states in the West, small-scale solar benefits from carve-outs not available to large-scale projects: Arizona and Colorado have distributed generation carve-outs, as does New Mexico together with a solar carve-out.

The federal government, states, cities and utilities also provide numerous incentives for small-scale solar systems. These incentives follow four structures:

- *Size-based*: paid on a $/W basis, and often with cap restrictions on payments per system based on either system size or total eligible disbursement
- *Output-based*: paid on a $/kWh basis for a limited number of years, starting at the beginning of a system's life
- *Credit-based*: paid on a $/kWh basis which may be worth many times the avoided cost of generation (eg, solar renewable energy certificates)
- *Tax-based*: usually awarded as a forgiveness of corporate or system sales taxes

One prominent incentive for small-scale solar is net energy metering. This allows renewable energy projects belonging to electricity customers to receive credit for power generated by the system and fed back into the grid. The credit offsets the customer's electricity bill.

Deployment

Small-scale solar in the US grew from cumulative installed capacity of 1.1GW as of 2008 to 4.8GW in 2012 (Figure 57). Residential and commercial-scale PV projects fall under distributed generation. Most projects are affixed on rooftops of homes or commercial buildings, warehouses and parking lots:

- *Residential* (0-10kW): new residential PV annual installations increased 33% year-over-year to 400MW in 2012. Most importantly, the third-party financing model, wherein a solar provider finances the upfront costs of a PV system for a homeowner in exchange for long-term monthly lease payments, has been a strong driver of new development. The residential market was approximately 13% of annual US capacity installed in 2012.
- *Commercial* (10-1,000kW): commercial-scale projects made up 38% of 2012 installed capacity in the US. Third-party financing has not been as common in this sector (compared to residential) because many customers choose to self-finance the system or are not investment-grade.

Figure 57: US small-scale PV build by type, 2008-12

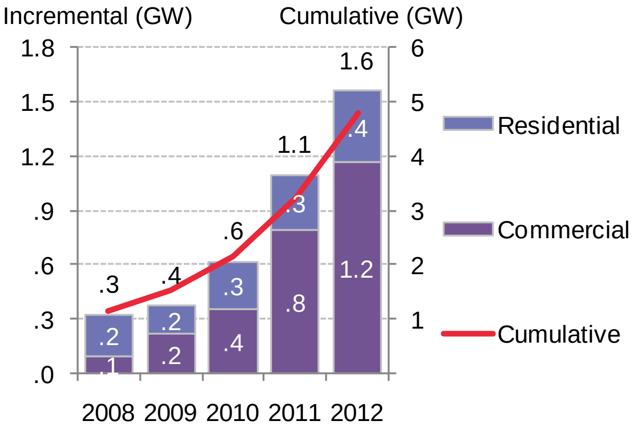
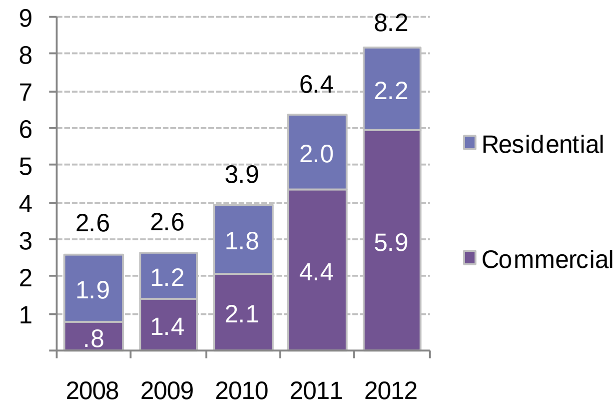


Figure 58: Asset finance for US small-scale solar projects by type, 2008-12 ($bn)

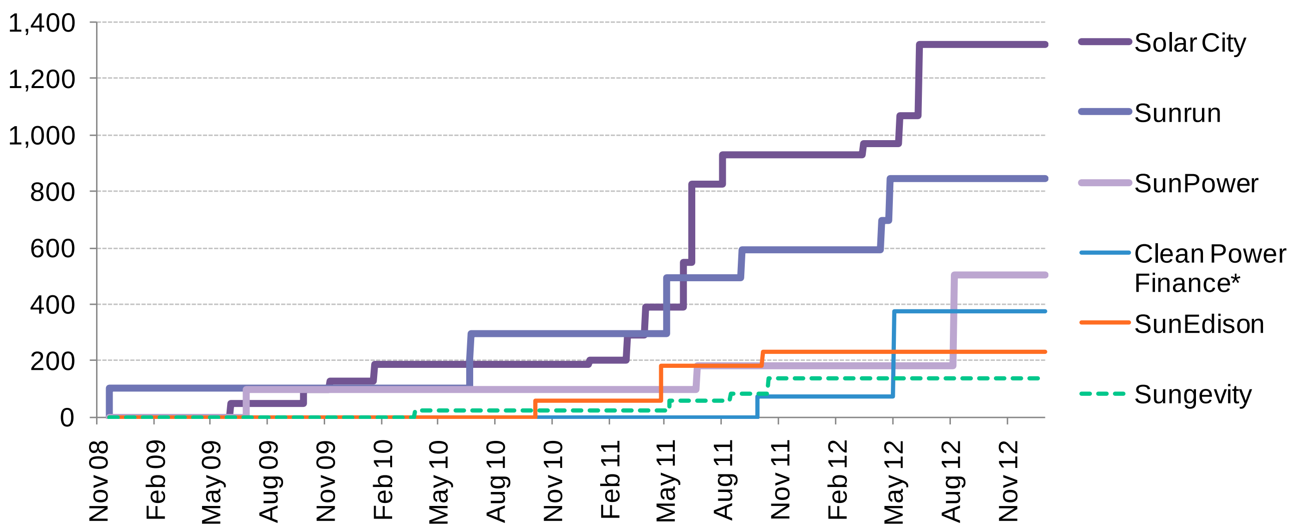


Source: Bloomberg New Energy Finance

Financing

Bloomberg New Energy Finance estimates that total asset finance for small-scale solar totalled $8bn in 2012, up from just $2.6bn in 2009 (Figure 58). In the third-party financing realm, companies such as SolarCity and Sunrun announced funds totalling $1.5bn last year. These funds are raised with contributions from investors (typically banks) that provide financing in the form of tax equity. Figure 59 shows *cumulative* funding closed by the most prolific third-party financiers.[1] In total, these have closed $3.6bn since Sunrun publicly announced its first fund in November 2008. SolarCity and Sunrun lead the pack with $1,320m[2] and $845m, respectively.

Figure 59: Cumulative funds closed by selected third-party financiers, November 2008–December 2012 ($m)



*Source: Bloomberg New Energy Finance Note: This captures fund size; actual capital invested is lower and non-public. Data is from publicly-available documents and submissions from investors; this may not include all non-public deals. Does not show all third-party financiers. Each fund contains unknown combination of equity, tax equity or debt. *The $300m Clean Power Finance fund raised on 3 May does not contain tax equity.*

1 These funds typically include sponsor equity, outside tax equity, and sometimes debt.
2 SolarCity disclosed in its December 2012 amended S-1 that it has closed $1,570m. The discrepancy between the $1,570m figure SolarCity reported and the $1,320m shown in Figure 59 likely results from SolarCity declining to make the size of one or more funds publicly available.

Economics

Residential and commercial-scale solar project costs have declined year over year as a result of falling module and inverter prices (Figure 60 and Figure 61). As of Q4 2012, crystalline-silicon modules in the US have reportedly been procured for under $0.78/W. However, these cheaper modules (as low as $0.65/W) are not easily financed with third-party capital because they are being sold by new, relatively unproven manufacturers.

Panels make up just a portion of system costs: developers have commented that the non-EPC costs of development (such as permitting and customer acquisition), as well as profit margins, make up approximately 50% of a system's price.

Figure 60: Capex – best-in-class cost of global commercial-scale PV, 2010-12 ($/W)

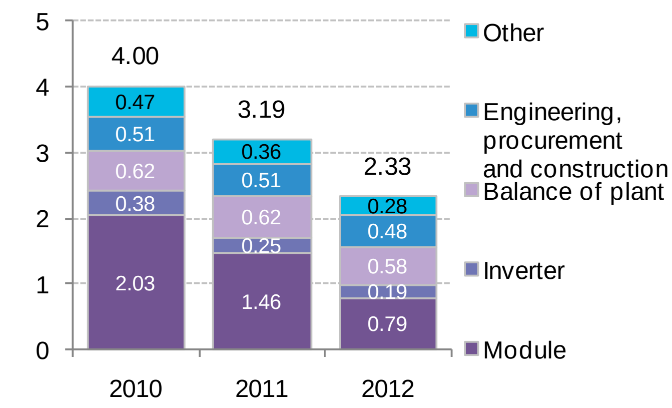
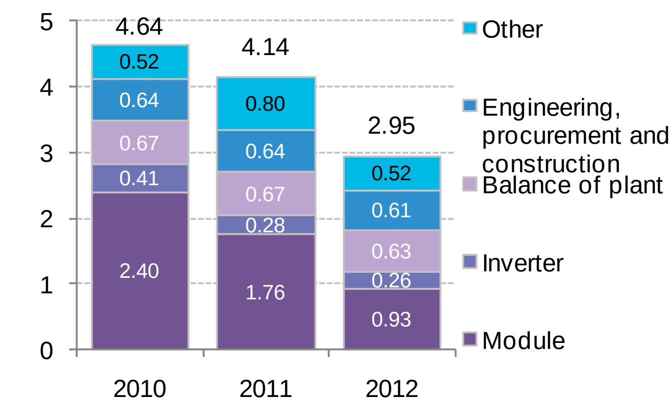


Figure 61: Capex – best-in-class cost of global residential PV, 2010-12 ($/W)



Source: Bloomberg New Energy Finance

Market dynamics

The residential installer market is fragmented. Of the US installed residential solar capacity in 2012, the majority was third-party financed, led by Sunrun and SolarCity. The latter is also a leader in the commercial sector of the US solar installation market. In December 2012, SolarCity raised $106m via an initial public offering on the Nasdaq. Those proceeds will be used to market and expand its commercial sector business. Likewise, the company should benefit from cheaper access to capital through its IPO to finance and expand its presence in the sector.

Third-party financing continues to grow in the US residential sector; market share for this financing model rose from 2% of installed capacity in Q1 2008 to 72% in Q4 2012 in California. This is not surprising: third-party financing offers homeowners a low upfront cost option to solar ownership. By contrast, commercial installations are still often financed and owned by the system host, particularly when the 30% cash grant in lieu of the tax credit was available. As of Q4 2012, only 49% of commercial installations were third-party financed in California.

5.2. Small- and medium-scale wind

Policy

Small-scale wind (<100kW)

The primary federal policy incentive available to small-scale wind is the ITC, which is applicable for turbines below 100kW in size through the end of 2016. Federal and state incentives in the form of rebates, tax credits, grants, low-interest loans and other funding assistance for small-scale wind reached $38m in 2011 – 27% greater than the $30m recorded in 2010 and surpassing the cumulative $35.6m in assistance over 2001-09. Among these incentives, state rebate programs are especially vital; diminished funding for these can greatly constrain the market for distributed wind. California has so far been the leader in funding of small wind installations, followed by Ohio, New York, Nevada, and Wyoming.

Medium-scale wind (100kW-1MW)

For projects over 100kW, the PTC is the primary federal incentive. The credit is applicable as long as construction begins before the end of 2013.

Deployment

Small-scale wind (<100kW)

In 2011 the US installed 19MW of small-scale wind capacity, according to data compiled by the American Wind Energy Association (Figure 62). In capacity terms, this was down 26% from 2010 levels. In units sold, however, the decline in installations was much smaller, down only 6.5%, from 7,811 units to 7,303 units. In part, this was a result of a move towards smaller turbines in the sub-100kW market. Sales of turbines less than 1kW increased in 2011, while sales of 10-100kW turbines fell. Half of all US turbine sales in this market segment are between 1 and 10kW.

Figure 62: US small-scale wind build, 2002-11

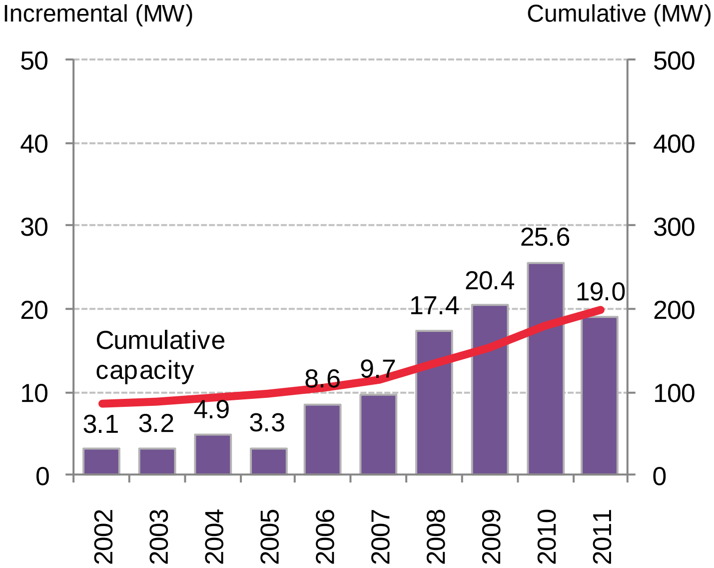
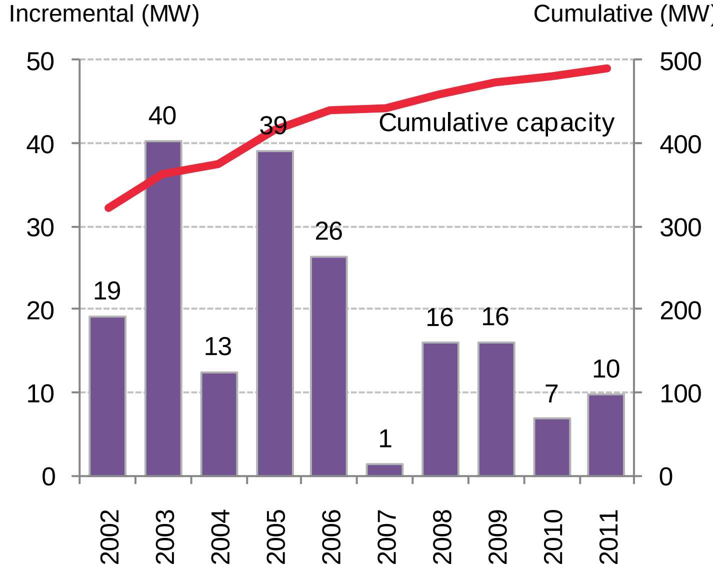


Figure 63: US medium-scale wind build, 2002-11



Source: Bloomberg New Energy Finance, American Wind Energy Association, Distributed Wind Energy Association, eFormative

Medium-scale wind (100kW-1MW)

Demand for mid-sized turbines has declined since 2005 (Figure 63). In 2011, 9.8MW of mid-sized capacity was installed in the US – down from a peak of 39.1MW in 2005.

Financing

Small-scale wind (<100kW)

Small wind is typically self-financed by a host, similar to how a homeowner might purchase a rooftop PV system. However, high upfront costs, long payback periods, and tax credit-based incentives can make project ownership unattractive or unviable. In the residential solar space, the development of third-party leasing and PPA models has helped remove these barriers and facilitated the wider adoption of distributed solar. But unlike solar, small wind faces unique challenges such as a lack of scale and widely variable performance and O&M costs on a site-by-site basis, and third-party financing models have not flourished.

Medium-scale wind (100kW-1MW)

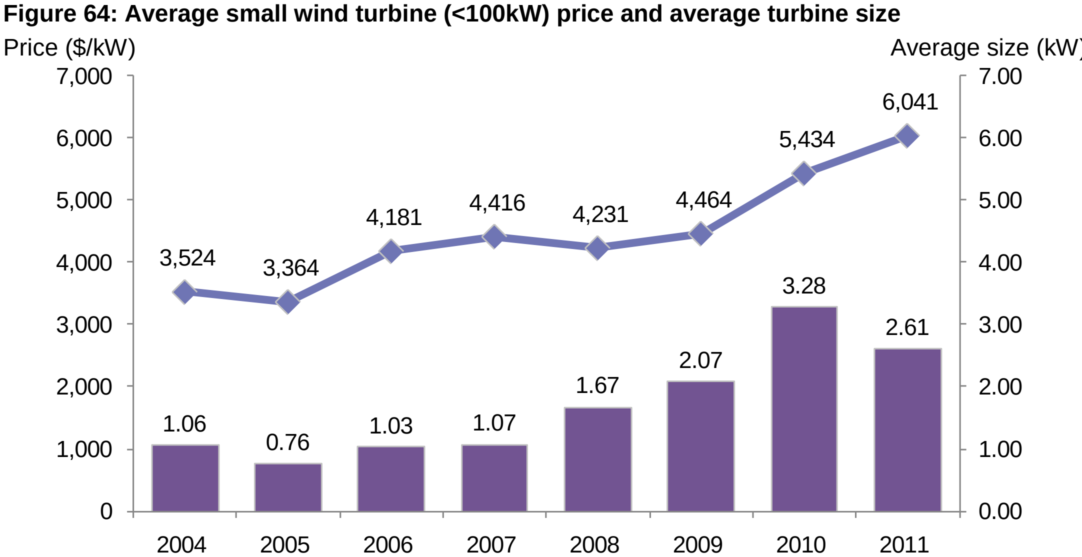
Due to the low volume of new build in recent years, financing activity has been limited in the medium-scale wind space.

Economics

Small-scale wind (<100kW)

In contrast to most renewable technologies, the average price of small wind turbines is increasing. On a $/W basis, turbine prices increased by 42% from 2008 to 2012 (Figure 64).

Figure 64: Average small wind turbine (<100kW) price and average turbine size



Source: Bloomberg New Energy Finance, American Wind Energy Association, Distributed Wind Energy Association, eFormative

Medium-scale wind (100kW-1MW)

The wider prevalence and lower average cost of large turbines has made the economics of medium-scale wind difficult. Turbines benefit from economies of scale; a larger model is often cheaper than a small one on a $/MW basis. As wind technology improved and larger turbines became more available, the average size of a turbine sold in the US (above 100kW) nearly doubled from 850kW in 2001 to 1.6MW in 2011.

Market dynamics

Small-scale wind (<100kW)

Declining PV costs and the increasing prevalence of third-party solar financing models is putting competitive pressure on small-scale wind. However, the international market is opening up: US small turbine exports increased over 200% over 2010-11, escalating from 7.8MW to 17.7MW. In total, sales of small turbines from US manufacturers rose 13% over 2010, including exports. A large market for small turbines is the UK, where generous feed-in tariffs have increased demand.

Medium-scale wind (100kW-1MW)

Currently, the US faces an oversupply of large (>1MW) turbine manufacturing capacity, making it difficult for medium-scale turbines to compete. The average capacity of mid-sized turbines peaked in 2005 at 950kW. In 2011, average medium-scale turbine size declined to 570kW as mid-sized manufacturers sought to differentiate themselves from larger utility-scale models with the introduction of several models in the 120kW to 500kW range.

5.3. Small-scale biomass

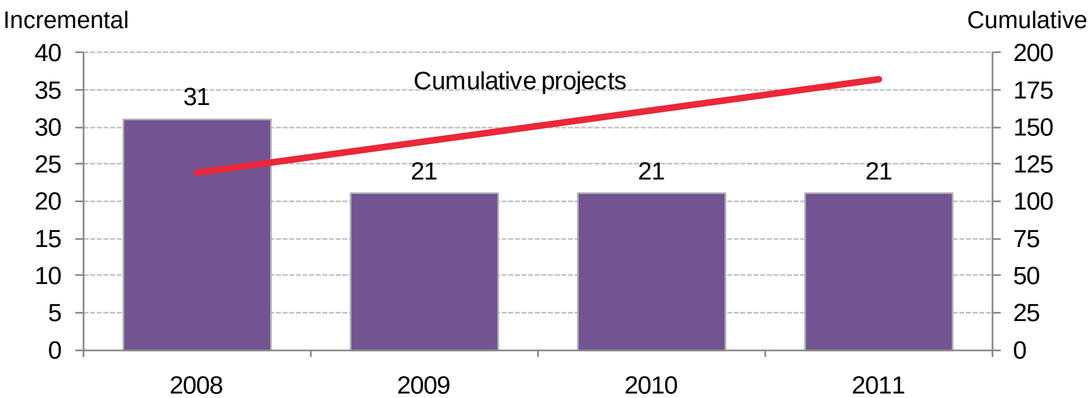
Policy

The main federal incentive for anaerobic digestion projects is the $11/MWh PTC for electricity-generating projects larger than 150kW.

Deployment

As of the end of 2011, 182 anaerobic digestion projects operated in the US (Figure 65). Of these, 154 had electric generators, totalling 83MW of capacity. At least 107 projects produce recoverable heat, either with or without electricity generation.

Figure 65: US anaerobic digester projects, 2008-11



Source: Bloomberg New Energy Finance, US EPA AgSTAR

Financing

Small anaerobic digestion projects at dairy farms can often be financed by a farm's owner. Larger projects have been developed by third parties. For example, the US's largest operating anaerobic digestion project – a $21.5m 4.5MW facility at the Double A Dairy Farm in Idaho – is owned by Camco International rather than by farmers.

Economics

Our analysis indicates that the LCOE of anaerobic digestion projects varies significantly, from $85-191/MWh (with LCOE for a typical project at $143/MWh). This pricing makes for expensive renewable energy on a utility scale, but distributed projects can be competitive with more expensive retail rates. Our analysis does not assume any co-generation, which can provide unique benefits to project owners.

Market dynamics

The majority of small biomass projects operate at dairy farms that produce large amounts of animal waste. These farms are located mainly in the Midwest, West and Northeast. A smaller number of projects are located at pig farms.

The average generating project size rose from 125kW in 2003 to 454kW in 2011. This increase has been driven by new development at larger farms.

5.4. Combined heat and power and waste heat to power

Policy

CHP sources generate electricity and heat simultaneously from a single source – a more efficient and cleaner alternative to producing these from separate sources; CHP plants can capture up to 80% of a fuel's energy, compared to less than 50% via the separate production of electricity and heat. Waste-heat-to-power installations capture the heat generated as a by-product from industrial processes and convert this heat into electricity through a process that does not involve burning any additional fuels or emitting any additional pollution (the energy conversion occurs via steam turbines, or other technologies for lower-temperature heat, just as geothermal energy uses underground heat to produce emissions-free electricity).

The US offers some support to CHP, though is less generous than to other renewables. Federal support began with the Public Utility Regulatory Policy Act of 1978 (PURPA), which mandated utilities to buy energy from qualifying CHP projects at the utilities' avoided marginal cost – though the Energy Policy Act of 2005 authorized FERC to lift PURPA obligations for utilities that operate in sufficiently competitive markets. Currently, the chief federal incentive for CHP is a 10% ITC, which expires in 2016; it is available only for the first 15MW of a project, and is limited to those below 50MW. Further federal support appears to be on the way. The EPA and DOE are actively pursuing an initiative to increase CHP deployment and in 2012 President Obama signed an Executive Order calling for a goal of 40GW of new CHP capacity by 2020.

Additional incentives exist on the state level; 18 states allow CHP or waste heat recovery to be eligible for renewable portfolio standards or energy efficiency resource standards (these policies are explained in Section 6.1).

Deployment

CHP facilities occupy a unique niche; projects tend to be built to supply a specific consumer with both electrical and thermal energy. They can be small and provide distributed generation, or large, utility-scale installations.

The CHP industry grew rapidly from 1985 through 2005 with new installations averaging 3,400MW per year. Annual capacity growth fell significantly in 2006, after PURPA requirements were weakened. New installations averaged just 570MW per year over 2006-11, due to stagnant US electricity demand and sluggish industrial growth. New installations totalled 2,336MW between 2008 and 2011 (Figure 66). CHP plants produce roughly 300TWh of electricity per year (Figure 67).

Figure 66: US CHP build, 2008-11

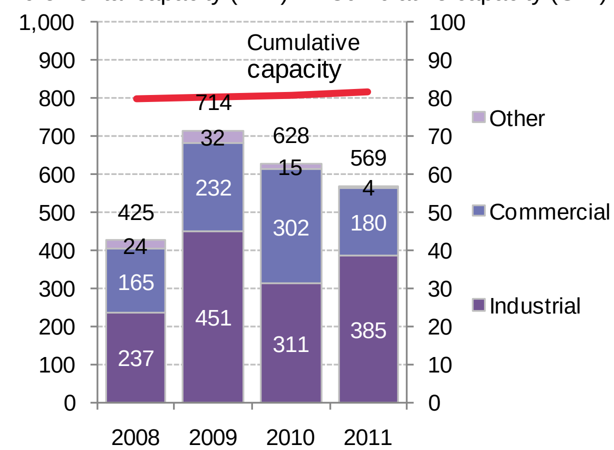
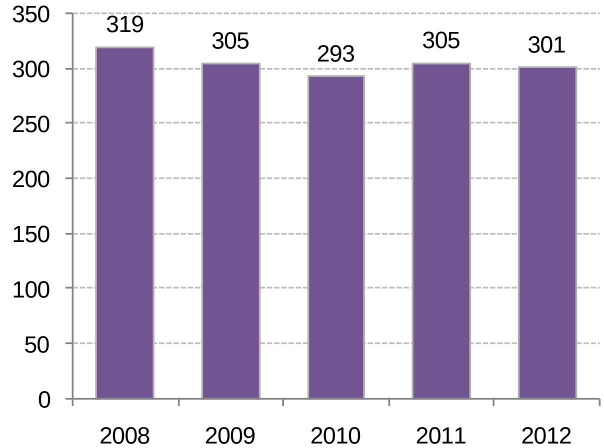


Figure 67: US CHP generation, 2008-12 (TWh)



Source: Bloomberg New Energy Finance, EIA, ICF International Note: This data comes from EIA, the best available source for generation data. However, EIA data on CHP is not comprehensive and so the generation figures may be underestimated. Specifically, EIA does not collect data for sites <1MW; EIA may not be aware of certain installations and thus may not send these sites a survey for reporting; and EIA categorizes some CHP systems as 'electric power' rather than 'industrial CHP', if these systems sell power to the grid while providing steam to an adjacent facility. All told, EIA data shows 70.3GW of CHP in the US, whereas ICF International's CHP Installation Database shows 82.0GW.

The industrial sector accounts for most of the capacity (Figure 68). Industrial plants, such as oil refineries and steel mills, have substantial demand for both electrical and thermal energy, which is often met via an onsite CHP plant. As a result, the largest owners of CHP plants include industrial asset owners such as Dow Chemical, ExxonMobil, and International Paper.

Figure 68: US CHP deployment by sector

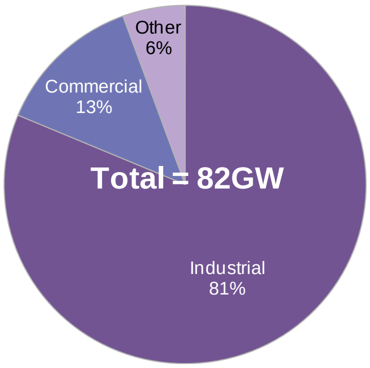
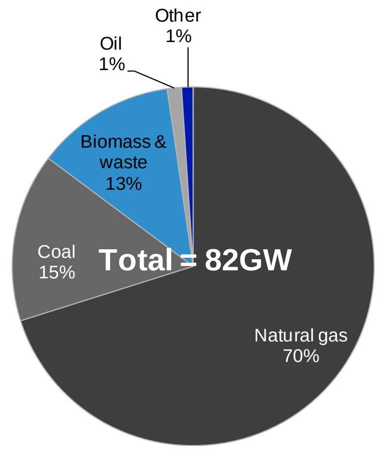


Figure 69: US CHP deployments by fuel source



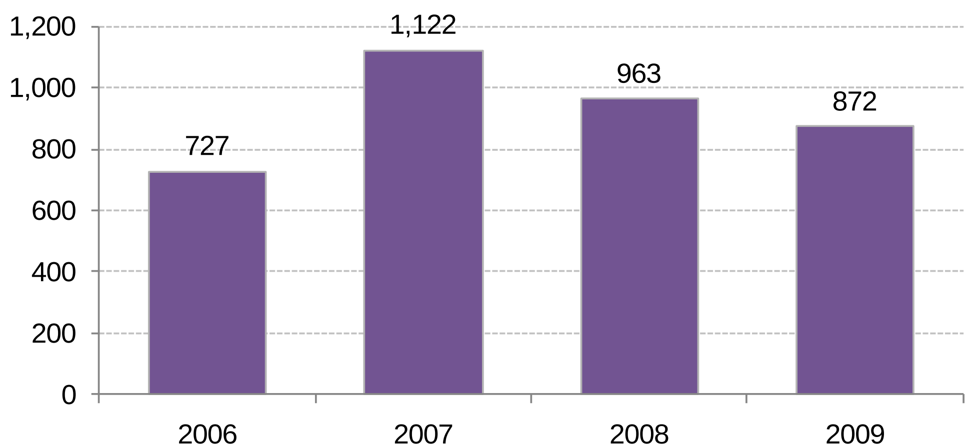
Source: Bloomberg New Energy Finance, ICF International

Nationwide, 87% of CHP capacity uses fossil fuels, and natural gas is the primary fuel source due to its low emissions and high efficiency (Figure 69). Renewable energy fuels 13% of capacity, all of it biomass and waste. Many of these projects are located at waste processing facilities, or at pulp and paper mills where generators use wood waste from the mill's processes as a feedstock.

Financing

Bloomberg New Energy Finance estimates that annual asset finance for CHP projects averaged $921m per year over 2006-09 (Figure 70). These figures were calculated by finding typical capex values for projects of different sizes (Figure 71) then calculating the weighted average capex for the year based on the blend of sizes for projects installed that year. It was assumed that projects achieve financing two years prior to commissioning – eg, for a project commissioned in 2011, it was assumed financing occurred in 2009.

Figure 70: Asset finance for US CHP projects, 2006-09 ($bn)



Source: Bloomberg New Energy Finance, ICF International Note: Bloomberg New Energy Finance does not track CHP asset finance in the same manner it tracks renewable energy financing. These figures are derived by assuming a two-year lag between financing and project commissioning and a $1.35m/MW estimated capex.

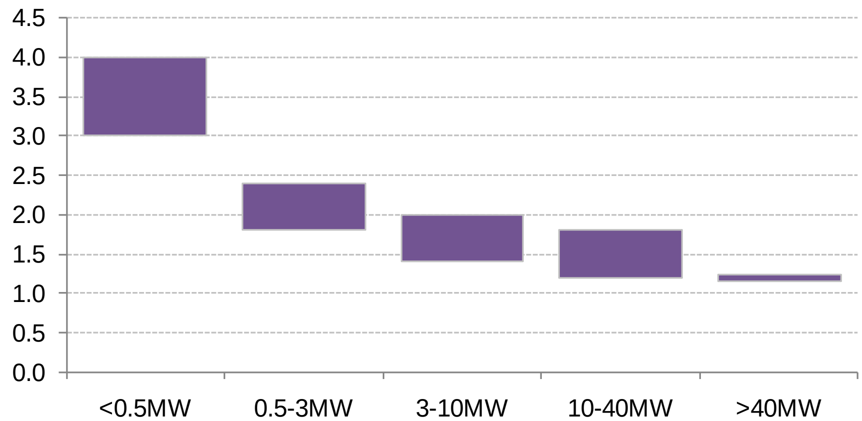
Economics

Large-scale (over 40MW) CHP capex average approximately $1.2m/MW, compared to approximately $1m/MW for a stand-alone utility-scale CCGT plant. The higher cost is primarily due to the additional equipment necessary to recover and process thermal energy. Despite the higher capex, the average LCOE for CHP of this size is around $73/MWh compared to $86/MWh for a CCGT plant.

To calculate the LCOE, Bloomberg New Energy Finance assumes the application of CHP to a standard CCGT facility. It was assumed that the plant is able to access a financing package of roughly 75% debt for 15 years (at a cost of debt of LIBOR + 550 basis points). The fact that CHP capex is higher than stand-alone CCGT is at least partially offset by the operational efficiency gains from utilizing otherwise wasted heat. The LCOE analysis accounts for these gains by applying a 'heat credit'. Based on data from the EPA's CHP Partnership Program, the heat credit is applied by reducing the heat rate of the plant to 5.1-7.0 MMBtu/MWh, down from 9.5-10 MMBtu/MWh, effectively reducing the amount of fuel required by the plant. This lower fuel usage drives lower LCOE.

Small-scale CHP installations have a higher cost of generation, but these installations can still work economically, as they compete against retail electricity rates, which are higher than wholesale rates.

Figure 71: Capex – capital costs for CHP installations ($m/MW)



Source: Bloomberg New Energy Finance, ICF International Note: ICF International reports that CHP capex has remained fairly constant since 2008.

Market dynamics

Stagnant growth in the US industrial sector has restrained new build. But recent market developments may usher in new opportunities:

- Low natural gas prices, driven by the shale gas boom, improve the economics of natural gas-fired CHP projects. However, variable fuel prices also presents unique risks.
- The October 2012 blackouts in the northeast US caused by Hurricane Sandy highlighted the attractiveness of distributed CHP as a source of reliable energy, as buildings with on-site CHP were able to continue supplying electricity even when the electric grid was down. According to ICF International, average CHP technical availability is in the range of 95.99-98.22%. CHP generation in conjunction with grid connection could lead to a lower risk of power outages for the offtakers of CHP plants.

5.5. Fuel cells (stationary)

Policy

The Emergency Economic Stabilization Act of 2008 authorized tax incentives for fuel cell projects. Those incentives were expanded to include grants and manufacturing tax credits as part of the American Recovery and Reinvestment Act of 2009. The most significant federal support mechanism is an ITC of 30% for qualified fuel cell property or $3,000/kW of the fuel cell nameplate capacity, whichever is less. This incentive is available for projects installed until 31 December 2016. Additionally, there is a federal residential energy-efficiency incentive which can be utilized as an ITC up to $3,334/kW for residential fuel cells in joint occupancy dwellings.

Recent legislation has further highlighted existing political support at the federal level for continued deployment of the technologies. The Fiscal Year 2013 Energy and Water Appropriations Bill approved by the US House of Representatives in June 2012 recognized advances achieved by fuel cell R&D programs at the Department of Energy and noted power- and transport-related opportunities for solid oxide fuel cells in particular. The National Defense Authorization Act of 2013 offers recommendations for increased use of fuel cells as part of the US military's energy strategy – eg, as a form of distributed generation, as an option for back-up power, and as a power source for unmanned vehicles.

Meanwhile, 34 states have active policy measures in support of stationary fuel cells. The most common is a tax credit or exemption. Additionally, electricity produced by fuel cells can be credited under RPS schemes although in some cases there are additional requirements such as fuelling by renewable hydrogen or biogas. Some states like California have Self-Generation Incentive Programs that offer grants for fuel cells.

Deployment

Years of research into stationary fuel cells are gradually bearing fruit; costs are falling and the number of installations is on the rise. There are five types of fuel cell differentiated by their underlying electrochemistry (Table 4). Molten carbonate and phosphoric acid fuel cells are the closest to commercial viability specifically for grid-scale applications. Solid oxide fuel cells are more versatile and are in development for stationary, portable, and auxiliary power unit applications. Polymer electrolyte membrane fuel cells are considered the best choice for transportation, and are also in use for small-scale distributed generation, back-up power, and CHP. However, the high cost of those two technologies remains a challenge.

Companies and investors interested in this sector note that fuel cells can act as baseload generators with power quality on par with conventional baseload generators.

Table 4: Comparison of fuel cell types

Fuel cell type	Typical system size	Efficiency	Applications	Notable US vendors
Alkaline (AFC)	10kW –100kW	60%	Military, space	UTC Power
Molten carbonate (MCFC)	300kW–3MW	50%	Distributed generation, utility	FuelCell Energy
Phosphoric acid (PAFC)	100kW–400kW	40%	Distributed generation	UTC Power
Polymer electrolyte membrane (PEMFC)	1kW–100kW	60%	Backup power, distributed generation, transportation	PlugPower
Solid oxide (SOFC)	1kW–2MW	60%	Backup power, distributed generation, utility	Bloom Energy

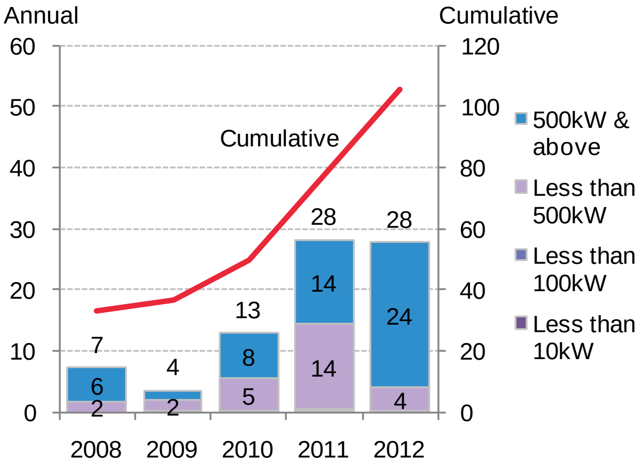
Source: Bloomberg New Energy Finance, US Department of Energy

During the last five years, on average 16MW/year of new stationary fuel cell projects have been deployed in the US, bringing cumulative installed capacity for active stationary fuel cell installations to over 100MW (Figure 72). These are distributed over 382 sites, of which 170 were deployed between 2008 and 2012 (Figure 73).

Before 2008 there were more projects below 10kW and below 100kW. The below-10kW category is primarily for residential and small and medium-sized enterprise applications, while below-100kW covers applications such as back-up and auxiliary power for commercial and industrial installations. More recently there has been a shift towards installations above 100kW which are suitable for grid-scale and utility applications. These systems are large enough to sign PPAs and qualify under RPS schemes where applicable.

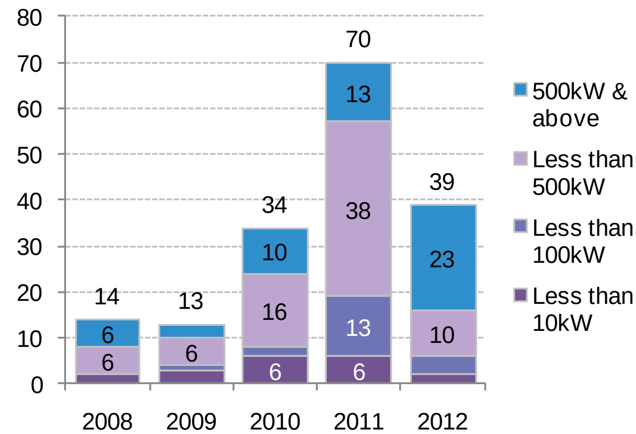
In 2011 there were a record 70 projects, over half of which were in the above-100kW category. The sharp increase in the number of projects that year was partly due to the expiration of the cash grant program.

Figure 72: US stationary fuel cell installations, by size of installation, 2008-12 (MW)



Source: Fuel Cells 2000, Bloomberg New Energy Finance. Note: for cumulative calculation projects older than 2003 have been excluded due to the average 10 year lifespan of fuel cells.

Figure 73: US stationary fuel cell installations, by size of installation, 2008-12 (number of installations)

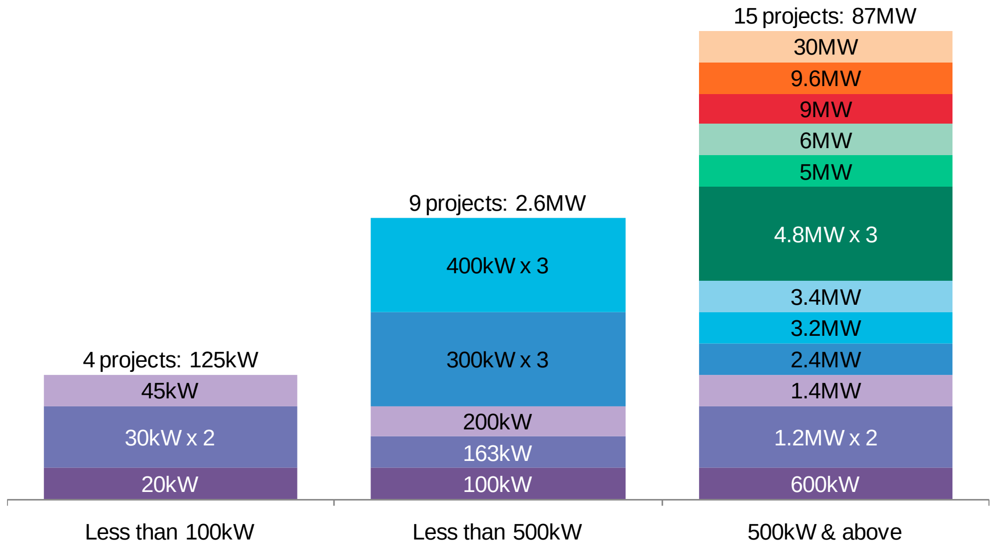


Source: Fuel Cells 2000, Bloomberg New Energy Finance. Note: installations across multiple locations are counted as multiple projects.

While the number of projects last year declined relative to 2011, annual new installation capacity remained the same at 28MW, as the average size of projects increased from 400kW in 2011 to 710kW in 2012.

There is currently a total project pipeline of 90MW spread over the next three years. As shown in Figure 74, half of the 28 announced projects are over 1MW, with the largest single project being Bloom Energy's 30MW Delmarva plant. Another notable project is a 14.9MW plant under construction in Bridgeport, Connecticut, expected to be placed in service by the end of 2013. The project was recently acquired from FuelCell Energy by Dominion, one of the country's largest utilities; FuelCell Energy will be retained as the project's builder and operator, and Connecticut Light & Power is its offtaker under a 15-year contract.

Figure 74: Announced fuel cell stationary projects in US by type



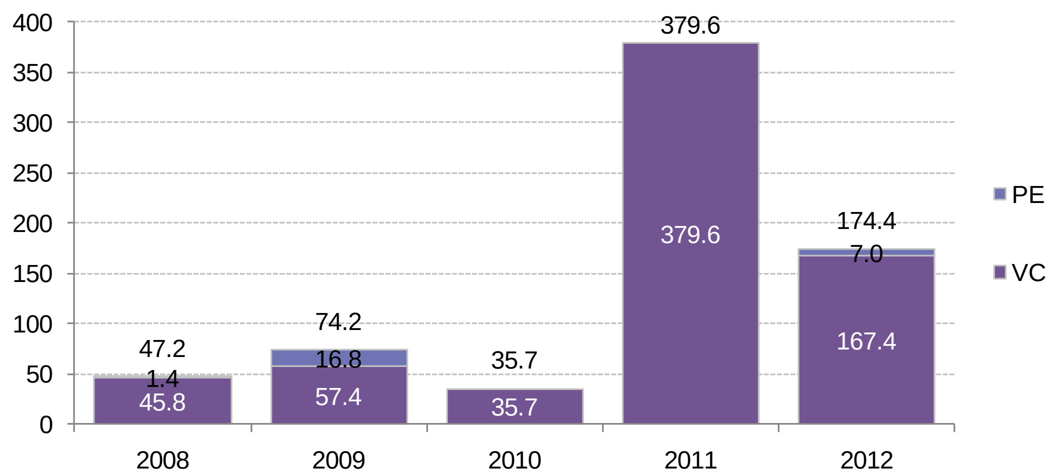
Source: Fuel Cells 2000, Bloomberg New Energy Finance. Note: Installations across multiple locations are counted as multiple projects. 'Announced' projects are those that have not yet been fully financed. Some projects have secured partial financing but not all of the required capital and permits.

Financing

Fuel cells have garnered significant attention from the venture capital community. In 2011, there was a record investment of $380m (Figure 75) thanks to the $250m funding of Bloom Energy. While venture capital investment in 2012 fell, it remained higher than in prior years. Bloom once again led the pack in 2012, raising $150m.

Asset financing has been small relative to renewable sectors such as wind and solar. Because fuel cell projects generate substantial tax credits, tax equity financing has been popular.

Figure 75: Venture capital / private equity investment in US fuel cell companies, 2008-12 ($m)



Source: Bloomberg New Energy Finance Note: Values include estimates for undisclosed deals.

Economics

Stationary fuel cells from players like Bloom, UTC and FuelCell Energy boast capacity factors (for electricity) of 40-50% and benefit from availability factors of over 99%, making them highly reliable and predictable. Data from the California Public Utility Commission indicates that all-in capex ranges from $3.9m/MW all the way up to $9m/MW, yielding an LCOE of $120-220/MWh. (The 14.9MW Bridgeport project is valued at $70-80m, corresponding to $4.7-5.4m/MW; its 15-year PPA is priced at $89/MWh, but the project also benefits from state incentives.) Roughly 40% of capital costs are attributable to the core fuel cell stack and insulation. Additional efficiency can be realized through the re-use of the heat generated from the units. The generators can be fuelled with either natural gas or biogas. Depending on the price of gas, fuel costs can make up around 40% of the LCOE. Due to the small scale of these projects, this analysis assumes that they are financed entirely with equity. As with all other LCOE calculations in this report, a 10% equity IRR is assumed.

Market dynamics

The combination of historically low natural gas prices, availability of federal investment tax credit for fuel cells, and state-level RPS schemes have strengthened the business case for stationary fuel cell projects for applications above 100kW (distributed generation, utility-scale). States receiving the most attention are California (due to its Self-Generation Incentive Program) and Delaware (due to the contract signed by the state with the local utility Delmarva and Bloom).

For applications above 100kW, molten-carbonate followed by phosphoric-acid fuel cells have a lower initial capital cost compared with solid-oxide fuel cells. Nevertheless, Bloom, which manufactures the latter, has been successful in signing up the most number of planned projects (91MW). Bloom's success partly stems from its innovative business model of offering to sell the electricity from the fuel cell system rather than selling the system itself.

FuelCell Energy has secured 38.9MW of projects for the next three years in the US (globally, it has the most projects planned (218.9MW) as a result of its partnership with Korea's POSCO Energy). With an eye on sub-megawatt applications to complement its molten-carbonate fuel cell products, FuelCell Energy acquired solid-oxide fuel cell manufacturer Versa Power Systems. The sub-100kW market has been limited due to the high cost of micro-CHP systems for residential and commercial buildings, but further cost reductions for solid-oxide and proton-exchange membrane fuel cells (PEMFCs) could open up this segment.

Another leading player in the US is UTC Power, with 5.6MW planned for the next year. In addition to manufacturing phosphoric-acid fuel cells systems for applications above 100kW, UTC Power makes PEMFCs for transportation applications and AFCs for military and space applications. In December 2012, UTC Power was acquired by ClearEdge Power, a manufacturer of high-temperature PEMFCs for micro-CHP applications, meaning that the combined entity will be able to compete across a broad array of applications.

5.6. Energy storage

Policy

FERC Order 755 has been an important policy development for the energy storage sector. The order requires independent system operators (ISOs) to compensate frequency regulation resources for the actual quality and quantity of regulation provided. It could boost annual revenues of energy storage assets providing regulation by a factor of 2-3, depending on how each ISO implements the new rules.

California's energy storage policies also merit attention. The state has consistently advanced a progressive set of policies and incentives. Table 5 details the structure and status of the three most important storage policies in California.

Table 5: California storage policies

Policy	Timeline	Status	Structure	Notes
AB 2514	2010-21	Signed into law, implementation underway	Establishes energy storage procurement targets for investor-owned utilities in 2015 and 2020 and for publicly owned utilities in 2016 and 2021	The CPUC decides upon IOU procurement targets by 1 October 2013 The publicly owned utility's local governing board decides on its procurement targets – if any are determined to be appropriate – by 1 October 2014
Self- Generation Incentive Program (SGIP)	2001-14	Active	Provides $2/W incentive to small behind-the-meter storage assets 50% of incentive upfront, 50% is performance based over five years	$83m annual IOU budget from the rate base was approved, about 10% of which is reserved for storage
Permanent load shifting (PLS)	2006-14	Active	Provides $0.25-1/W incentive to end-users Funded from the rate base	$32m annual IOU budget IOUs are being directed to standardize programs state-wide for PLS technologies (which shift load from times of peak power to off-peak times)

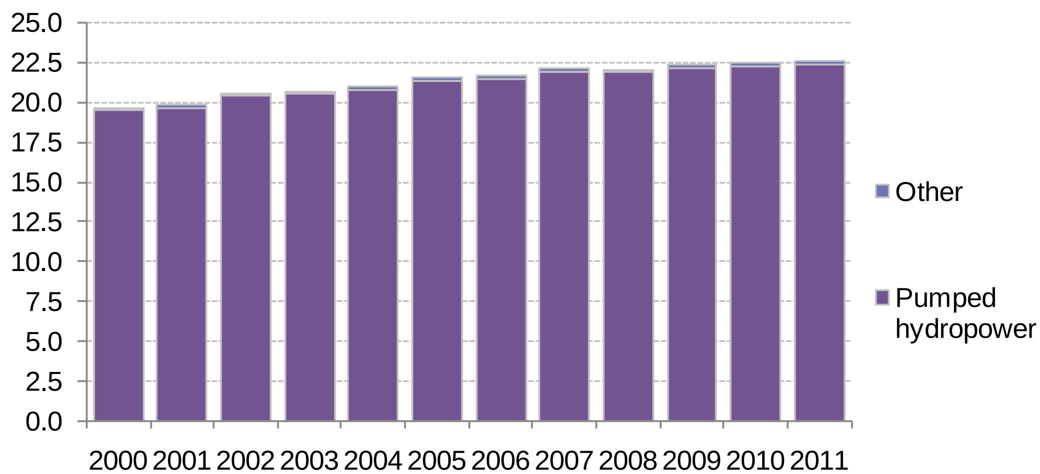
Source: Bloomberg New Energy Finance

The US American Recovery and Reinvestment Act provided $185m for energy storage demonstration projects. The total cost of these 16 projects amounts to $585m (with the remaining $400m coming from the private sector). Additionally, since its inception in 2009, the Advanced Research Projects Agency-Energy (ARPA-E) has invested $85m in fundamental research in energy storage.

Deployment

Pumped hydropower makes up almost the entirety of the US energy storage market, with 22.3GW of installed capacity (99% of existing total storage capacity). It also comprises the bulk of new capacity: net summer capacity for pumped hydro has increased by 2.9GW since 2000. Overall, the energy storage market in the US has increased 15% since 2000 (Figure 78).

Figure 76: Cumulative energy storage capacity, 2000-11 (GW)



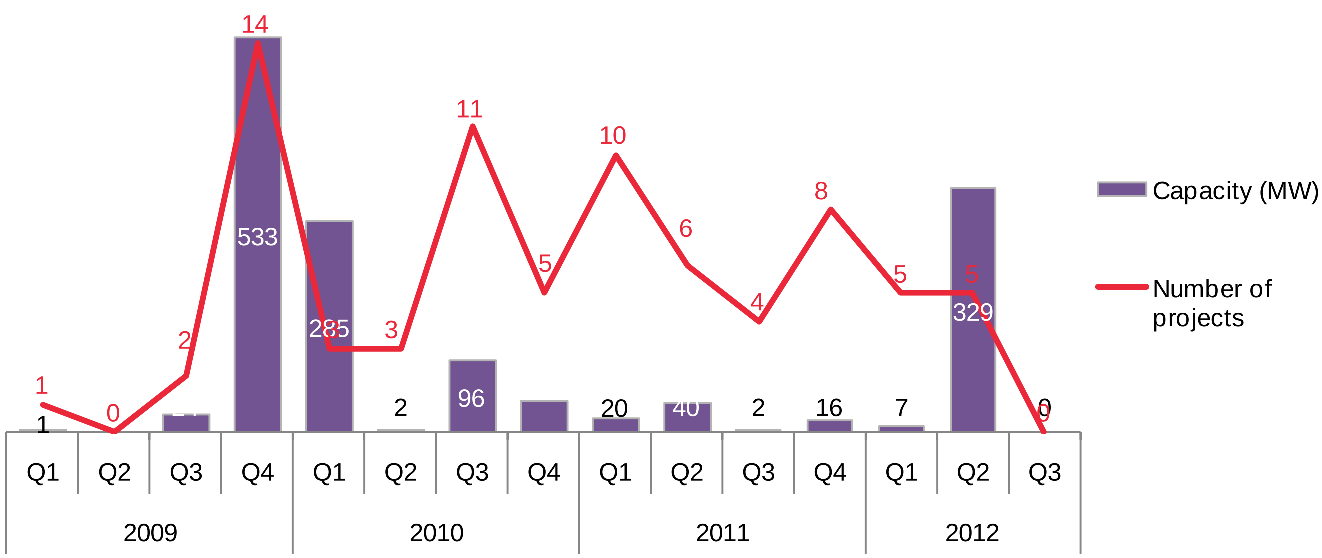
Source: Bloomberg New Energy Finance, EIA Note: Pumped hydropower capacity is net summer capacity.

Non-hydropower storage technologies comprise a much smaller share of the market. Total installed capacity of these technologies (including batteries, flywheels, and compressed air) has grown from 136MW to 289MW over the past decade. The stimulus funding towards the end of 2009 helped promote the growth of new storage technologies, but since then, many of the projects that received support are still waiting to be commissioned, and the number of newly announced projects remains low (Figure 77).

There are four major obstacles to the adoption of storage:

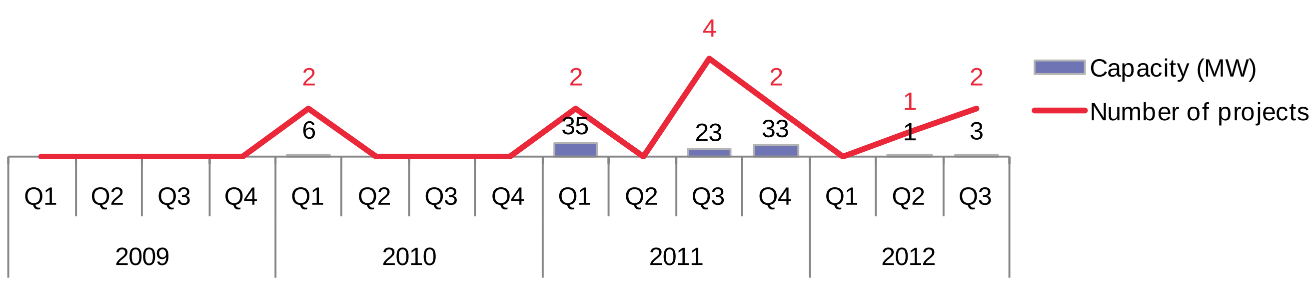
- *Market structure:* industry players find fault with the failure of markets to properly compensate the benefits provided by storage, including the ability for technologies to ramp up rapidly or to absorb energy in periods of excess output from intermittent resources
- *High cost:* with the exception of lithium-ion batteries, there have not been significant cost reductions in commercially available energy storage technologies.
- *Unclear application value:* a significant number of utilities and other potential storage buyers have now started one or two projects looking at storage. It will take time for their assessment of the true financial value of storage to be complete and be used to inform further, larger-scale purchases.
- *Worsened economics:* although frequency regulation does have a clear value proposition, the economics have deteriorated significantly in the past year in the US due to low-cost natural gas.

Figure 77: Announced non-hydropower energy storage projects in the US (MW and number of projects)



Source: Bloomberg New Energy Finance

Figure 78: Commissioned non-hydropower energy storage projects in the US (MW and number of projects)



Source: Bloomberg New Energy Finance

Economics

The cost of storage technologies remains a significant barrier to further adoption. Compared to the most widely used storage technology – pumped hydropower – most new technologies are significantly more expensive both on a capex and capex per cycle basis. In the past couple of years, however, the costs of new storage technologies have declined. In particular, the lithium-ion battery sector has advanced along its learning curve due to increased electric vehicle production.

Figure 79: Capex – capital costs of select storage technologies ($/kW)

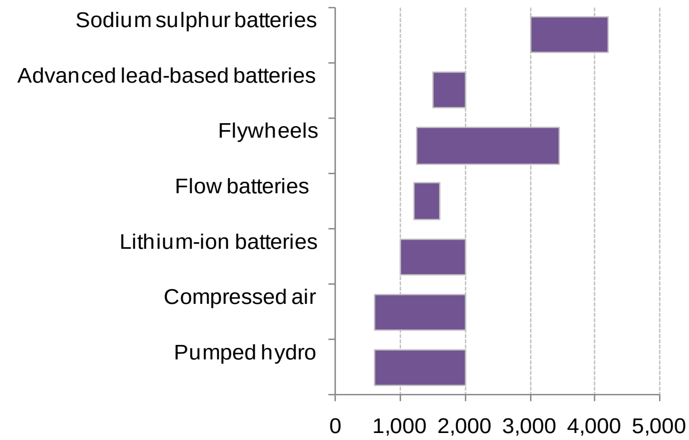
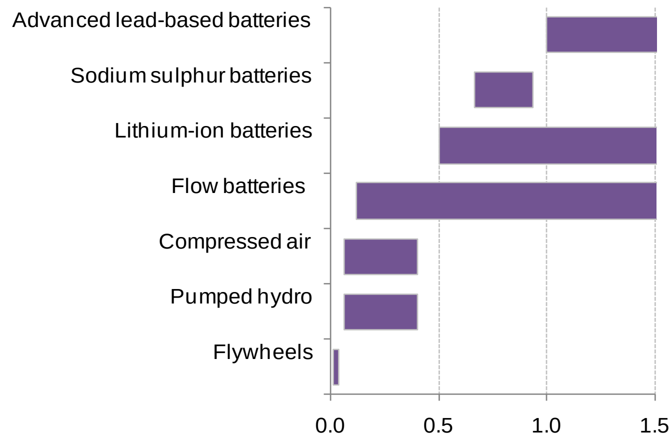


Figure 80: Capex – capex per cycle costs of select storage technologies ($/kW/cycle)



Source: Bloomberg New Energy Finance

A full assessment of storage economics requires a detailed look at potential revenue as well as costs. There are three main applications at the generation level: arbitrage, frequency regulation and system capacity. Across all US ISOs, down to individual pricing zones, none of the three applications currently makes economic sense. The cost of storage systems is far higher than the potential revenue gained.

Yet a turning point is on the horizon. The introduction of FERC Order 755, along with the continuing decline in technology costs and a rise in natural gas prices, could turn frequency regulation into a profitable market segment in a number of ISOs in the near future. For storage assets focused on long duration, high premiums for demand response have strengthened their economics. These premiums can comprise energy and capacity market payments, and even payments from utility-administered programs in some cases. But these may take a long time to become economical.

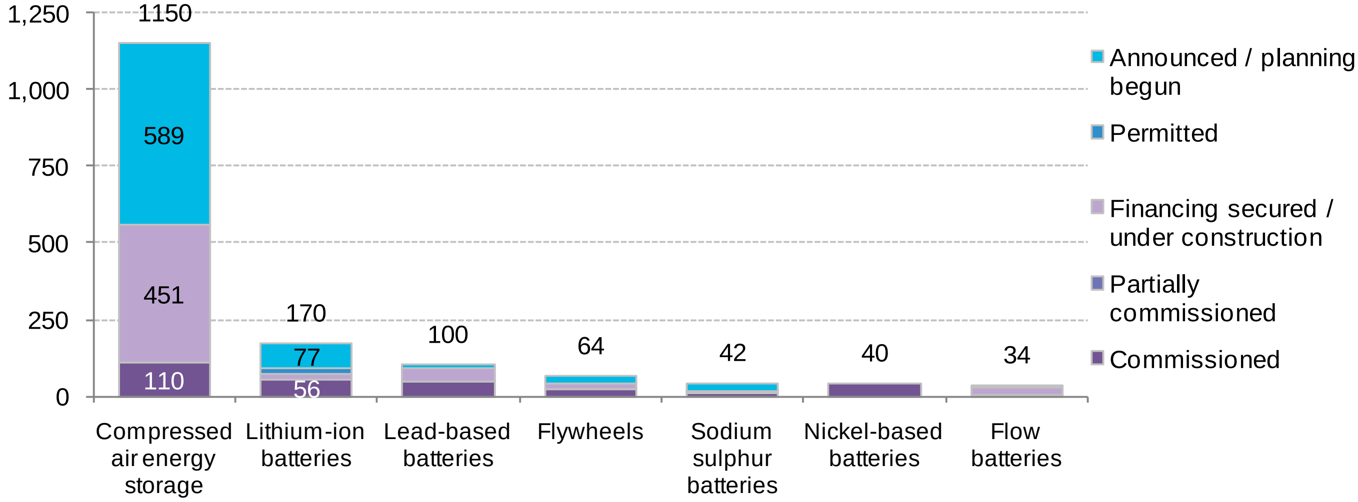
Other applications, including transmission and distribution applications and renewable integration, still require significant regulatory changes for the financial benefit of storage to be recognized.

Market dynamics

Developer interest in pumped storage technology has risen in recent years: FERC received 110 preliminary permit applications over 2008-11, compared to just 16 the previous four years. Over 50 projects totalling 44GW in capacity have received preliminary permits, though not all will be built.

Among non-hydropower technologies, compressed air energy storage is the leader in terms of installed capacity (Figure 81). However, there is just one commissioned compressed air project in the US with another six in the pipeline, four of which are unlikely to be commissioned soon. The technology that has seen the most progress has been lithium-ion batteries, where US companies such as A123 Systems have pioneered technology improvements (though not without risk, as demonstrated by A123's bankruptcy in 2012).

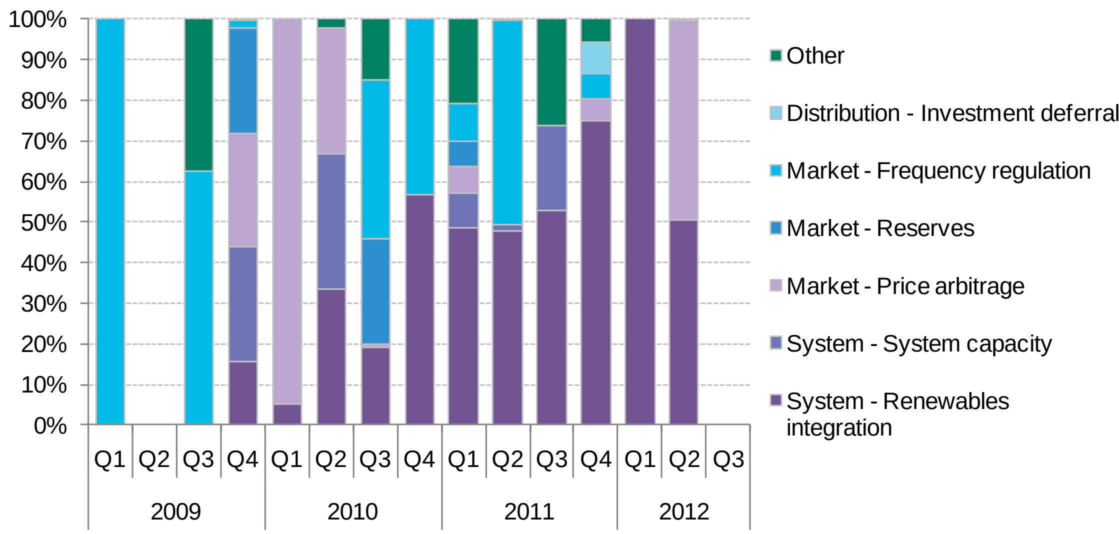
Figure 81: Non-hydropower energy storage projects in the US by technology (MW)



Source: Bloomberg New Energy Finance Note: Pumped storage is not included in this chart as it would dwarf all other technologies.

In terms of *application mix*, in recent years, the storage sector has increased its focus on renewable energy integration (Figure 82). At least 11 pumped storage projects have received preliminary permits in California, which has one of the most ambitious RPS programs in the country. Other commercial storage projects using technologies such as batteries are starting to appear to help integrate large-scale wind and solar on islands. However, most of these are still demonstration projects.

Figure 82: Non-hydropower application mix of announced energy storage technologies in the US (% by MW)



Source: Bloomberg New Energy Finance Note: Empty columns represent quarters where there were no new projects announced.

Two companies have led the battery market so far: A123 Systems and Xtreme Power. The former has been particularly dominant in the frequency regulation segment through its partnership with AES Energy Storage; Xtreme, however, has been recognized as a leading system integrator specializing in renewable integration.

5.7. Carbon capture and storage (CCS)

Policy

There are no federal policies to mandate CCS at power or industrial plants – though there are policies that force high-emitting plants to consider at least adopting CCS and potential policies that appear to discourage new coal plants to proceed without CCS.

Specifically, as of 2011, the US EPA requires new or modified sources with high emissions (>25,000tCO_2) to consider CCS as a potential option among ‘available control technologies’ as part of the sources’ permitting process, as per the Prevention of Significant Deterioration and Title V Operating Permit programs under the Clean Air Act. However, the EPA expects most sources will eliminate CCS as an option that is still too expensive. Additionally, in March 2012, the US EPA released a proposed stationary-source CO_2 emissions standard for new fossil-fuelled power plants. The standard – 1,000lbCO_2/MWh, or 0.45tCO_2/MWh, corresponding to about a 50% CO_2 emissions reduction on unabated coal-fired power – can be achieved by combined cycle gas plants without additional controls, but new coal-fired plants would require CCS to reach those levels. This standard is not expected to drive a CCS market, however, as new power plant build in the US will likely be dominated by gas plants that do not require CCS. The EPA will finalize the standard in 2013.

The federal government also currently offers a tax credit, known as a ‘45Q’ credit after its title in the federal tax code, for CCS installations. The credit, created under the Emergency Economic Stabilization Act of 2008, ranges from $10/t$CO_2$ for CO_2-enhanced oil recovery (CO_2-EOR) projects to $20/t$CO_2$ for geologic storage without any associated hydrocarbon production. As of late 2012, the program had only been about 30% subscribed (approximately 20.8m tCO_2 out of 75m tCO_2 authorized). In early 2013, the government announced a new $150m in the 48C program (manufacturing tax credits) for which CCS equipment manufacturers are eligible.

Illinois is the only state with a specific portfolio standard for coal-fired CCS power plants, though other states have provisions for CCS in their portfolio standards or goals. Illinois requires utilities to source a portion of their total electricity supply, starting at 5% in 2015 and increasing thereafter, from coal plants with CCS (minimum 70% CO_2 capture rate). Two projects are currently in development, but it is unlikely these or any other power plants with CCS will be operational in Illinois by that date – meaning the portfolio standard will likely not be met. Several other states, including Indiana, Wyoming, Texas and Mississippi, have enacted CCS enabling regulations surrounding CO_2 storage liability and pipelines and incentives such as tax breaks.

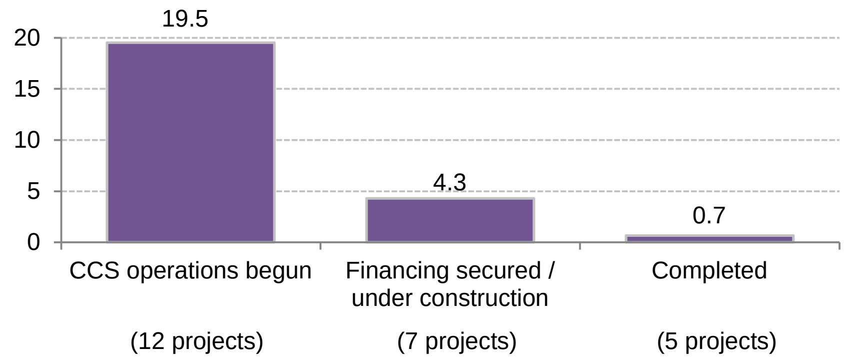
Deployment

Bloomberg New Energy Finance’s definition of CCS considers any project that captures and stores CO_2 that would otherwise have been released. This includes projects that separate CO_2 from natural gas processing facilities and from chemical plants (eg, plants involved in fertilizer production and hydrogen production) and that inject that CO_2 for EOR. The threshold is projects that are ‘pilot scale’ and larger, defined as greater than 10MWe. This definition for CCS is not necessarily an industry consensus; other industry experts draw the line more tightly, counting only projects which capture CO_2 from demonstration-scale power or industrial plants – ie, equivalent of 100MWe, about the minimum size of a single boiler unit, or larger.

The US CCS sector is the largest globally, but much of this deployment has rested on CO_2 captured from natural gas processing facilities, government-funded pilot facilities, or projects that draw on ancillary revenue streams. The 12 operational installations are injecting an estimated total of

20MtCO2/yr (Figure 83), 91% of which is used in CO2–EOR. Several of these projects started operations in the early 2000s or before, all for CO2–EOR. Developers have secured at least a majority of required financing or started construction for an additional seven projects that, when operational, will add another 4.3MtCO2/yr to the current annual injection rate. Approximately 92% of that CO2 is also slated for EOR.

Figure 83: Total CO2 injection rate by current status of US CCS projects (MtCO2/yr)



Source: Bloomberg New Energy Finance Note: 'Completed' are pilot-scale projects no longer operational.

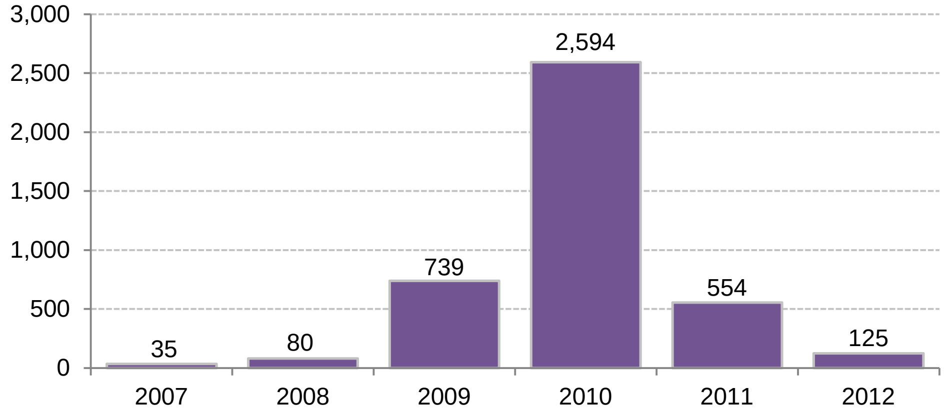
But overall, CCS deployment in the US has encountered serious difficulties, with many high-profile projects running into barriers such as difficulty gaining regulatory approval, insufficient regulatory frameworks regarding subsurface ownership, and long-term liability issues and cost overruns during construction. On paper, at least, projects that can utilize the CO2 in some way have a higher chance of success, but only somewhat. CO2 sale alone is generally insufficient to cover the revenue gap between electricity sales and economic viability. Of the projects that are demonstration-scale or larger, that have benefited from government grants, and that are intended for long-term deployment, only one has come to fruition: Air Products' Port Arthur project which captures 1MtCO2/yr from two steam methane reformers at an oil refinery owned by Valero near Port Arthur, Texas.

Financing

Asset financing for US projects that are at relatively advanced stages of development – ie, that have successfully reached final investment decision (FID), have started construction, or are operational ('post-FID' projects) – peaked in 2010 at $2.6bn (Figure 84). Most of the 2010 spending was for Southern Company's 582MW (net) integrated gasification combined cycle (IGCC) plant in Kemper County, Mississippi. About 65% of the plant's CO2 emissions will be captured and transported via a 60-mile pipeline, and sold on a long-term contract to an existing EOR company in the state. The $2.4bn project is supported in part by a $270m DOE grant and is currently under construction, slated for completion mid-2014.

Investment activity was somewhat meagre in 2012, with only $125m across two deals, and in 2013 just one large-scale US project is slated to start construction (though it is quite possible this timeline will not be met). The project in question is Summit Power's 217MW (net) polygeneration facility in Penwell, Texas known as the Texas Clean Energy Project. The majority of its revenue will come from urea production – a by-product of the coal IGCC process Summit intends to employ – with secondary flows from electricity and CO2 sales. It is expected to call for roughly $3bn in asset financing, of which over $1bn was pledged by the Chinese Ex-Im bank in 2011. This financing may close in 2013, making Summit the recipient of the first finalized debt for a CCS project. Historically, since 2000, the US has invested $4.5bn in CCS asset financing, more than any other country, representing 30% of all investment in post-FID projects globally.

Figure 84: Asset finance for post-FID US CCS projects, 2007-12 ($m)



Source: Bloomberg New Energy Finance Note: Values do not include estimates for undisclosed deals

Companies have financed CCS projects to date on balance sheet with assistance from a combination of grants and tax incentives. The federal government made about $950m in tax credits available for pre-FID active – ie, not cancelled – CCS projects since 2007. The 45Q tax credit, described above, is also available on a limited basis for CO2 storage.

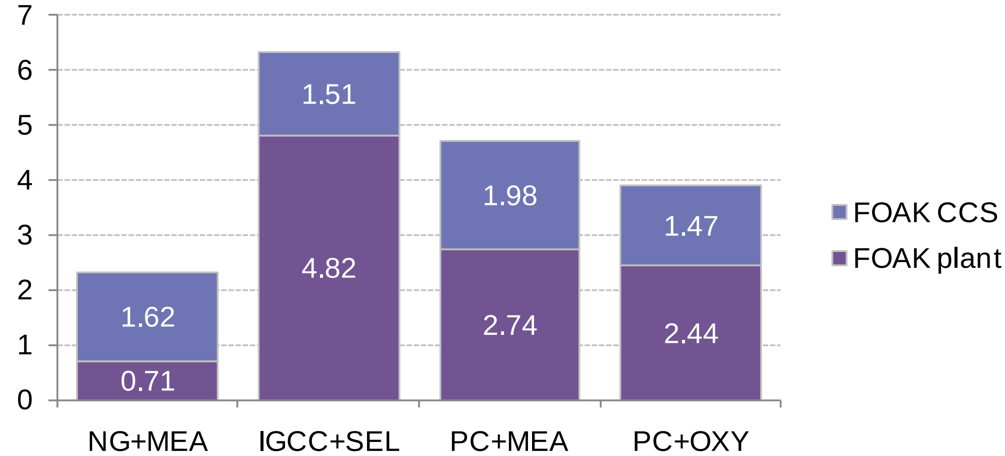
In addition, pre-FID projects in Texas, Louisiana and Wyoming may have low-cost funds available from tax-exempt bond issuances. Developers of three US projects have tapped into federal or county bonds for infrastructure development. For example, NRG Energy secured $54m in tax-exempt bonds, part of which will be used to finance the CCS portion of its 250MW (net) WA Parish retrofit coal-fired power plant in Texas. Other companies using bond financing are New York-based Leucadia for its Lake Charles coal-to-liquids plant in Louisiana and Houston-based DKRW Advanced Fuels for its Wyoming coal-to-liquids plant. However, despite having secured infrastructure bonds, these projects are not yet fully financed and whether they will reach construction is uncertain.

Economics

The 'first-of-a-kind' costs for CCS are estimated to be significantly higher than expected 'mature' capital costs, depending on the technology ('mature' costs means the costs that are likely achievable once these technologies are deployed extensively, on the order of tens of gigawatts).

Figure 85 shows capital costs of 'first-of-a-kind' installations; these capital costs are split into costs of the plant and the costs of the CCS-specific components. These costs are estimates; actual values are unknown until the first set of projects comes online.

Figure 85: Estimated first-of-a-kind (FOAK) capital cost for CCS projects ($m/MW)



Source: Bloomberg New Energy Finance Note: Costs based on 250MWe base plant and capture. 'FOAK' denotes first-of-a-kind. NG+MEA is natural gas combined cycle plant with post-combustion (amine) capture, IGCC+SEL is integrated gasification combined cycle plant with pre-combustion (Selexol) capture, PC+MEA is pulverized coal with post-combustion (amine) capture, and PC+OXY is coal oxycombustion plant with cryogenic CO_2 capture.

Market dynamics

Public funding for research and large-scale projects is a major driver of current US CCS activity. More than half of active US projects were supported by DOE grants, but most need additional drivers such as a revenue stream from selling CO_2 to the EOR industry. Non-grant supported projects are exclusively those capturing or separating CO_2 to sell for EOR.

About 70% of CO_2 used for EOR comes from natural sources, and as oil prices – and CO_2 demand – have climbed in recent years, anthropogenic CO_2 supplies have also increased. The main anthropogenic CO_2 source is from natural gas processing plants which already supply about 13MtCO2/yr. Planned expansions at gas processing plants along with CO_2 capture from power and industrial sources could add 10MtCO2/yr by 2016, which may not be enough to meet demand.

The price of CO_2 for EOR is currently in the range of about $20-40/tCO2. At those prices, CO_2 capture economics only work for natural gas processing and for some industrial processes (eg, ethanol plants). At least one US power generator with a planned CCS project, NRG Energy, may form a joint venture with an EOR company to receive oil revenue to improve CO_2 capture economics.

SECTION 6. DEMAND-SIDE ENERGY EFFICIENCY

Energy intensity of commercial buildings has decreased by over 20% since 1980, propelled by technology improvements and efficiency standards, such as those for heating and cooling units and for thermal performance (ie, insulation). Overall, US utility budgets for energy efficiency reached $7bn in 2011 (the latest available year for which data exists). Demand response capacity has grown by more than 250% from 2006 to 2011, allowing major power consumers such as manufacturers to cut their energy costs and utilities to scale back production from some of the costliest power plants. Some 46m smart meters have been deployed in the US, while spending on smart grid roll-outs hit $4.3bn in 2012, up from $1.3bn in 2008.

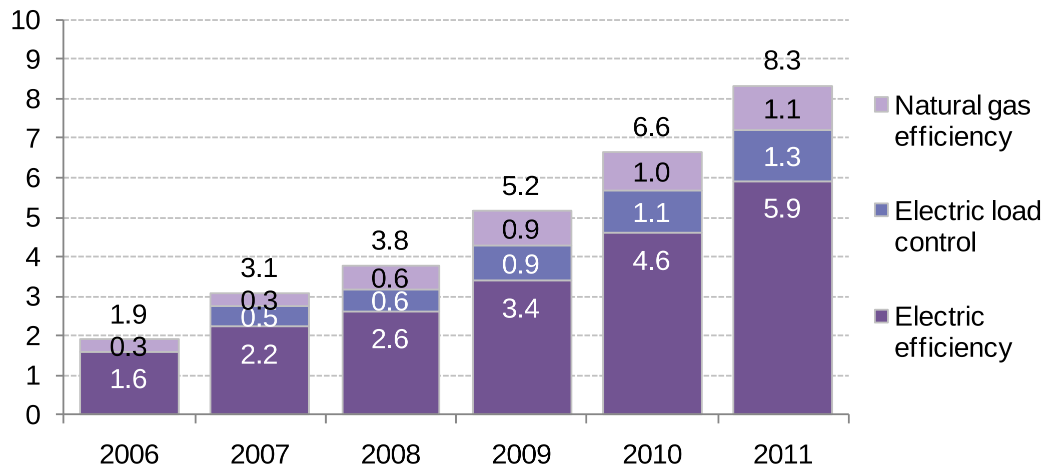
6.1. Energy efficiency

Policy

Utility energy efficiency legislation

US utility budgets for energy efficiency expenditures stood at approximately $7bn in 2011 (not including load control), up from $1.9bn in 2006 (Figure 86), as estimated by the American Council for an Energy-Efficient Economy (ACEEE) and the Consortium for Energy Efficiency (CEE). This higher spend can be attributed to the widespread uptake of two types of state-level policy: decoupling (or similar) measures and energy efficiency resource standards (EERS).

Figure 86: Utility spending on energy efficiency and electricity load control, 2006-11 ($bn)



Source: ACEEE, CEE, Bloomberg New Energy Finance. Note: Figures for 2006-08 represent expenditure, 2009-2011 represent budget. Natural gas and electric efficiency data comes from ACEEE, load control from CEE.

Decoupling refers to regulatory frameworks for setting rates wherein a utility's revenues are decoupled from the volume of kWh that they sell, removing a disincentive for investing in energy efficiency. Under EERS schemes, utilities are required to implement energy efficiency measures, typically among their consumers, equivalent to a target volume of kWh (usually specified as a fraction of the previous year's kWh sales).

Both policy types have been widely adopted over the course of the past decade (Figure 87). Since 2005, the majority of states have introduced decoupling or some similar legislation – only 10 states do *not* have any decoupling policy for either electricity or natural gas. EERS has seen a similar but slightly slower rate of adoption among states since the middle of the last decade – at present 22 states have yet to adopt the mechanism for either electricity or natural gas.

Although EERS and decoupling can be implemented independently, they are strongly complementary – the former drives utilities to implement energy efficiency and the latter removes their disincentive to do so. At present 21 of the 29 states with EERS requirements for electricity also have some kind of decoupling legislation for electric utilities. For natural gas the equivalent figures are 12 of 13.

Figure 87: US states with decoupling for electricity policies, 2000-12

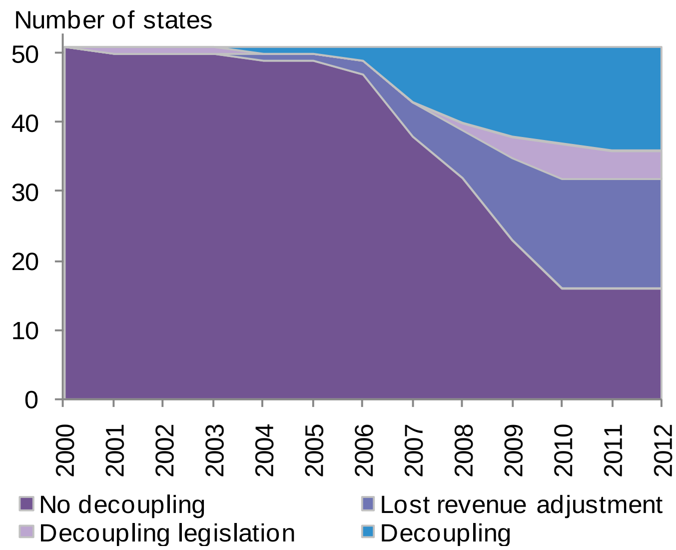
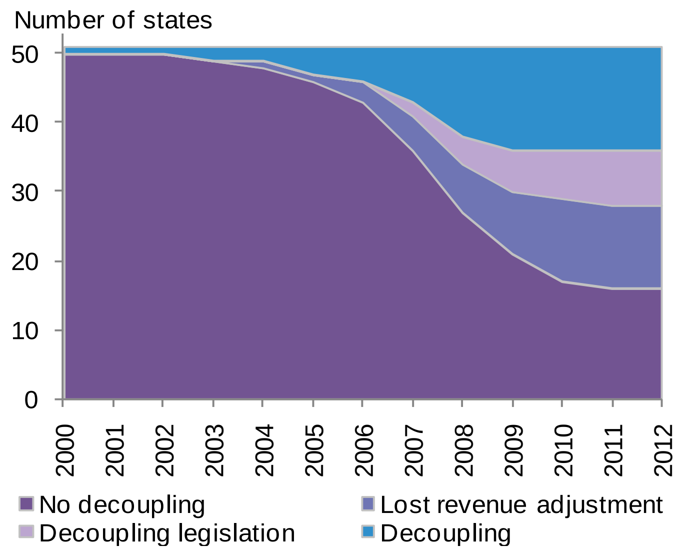
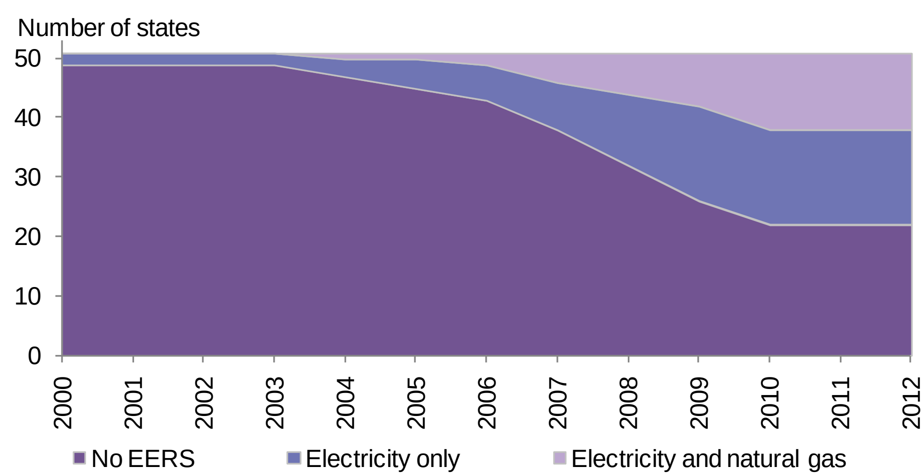


Figure 88: US states with decoupling for natural gas policies, 2000-12



Source: ACEEE, Bloomberg New Energy Finance. Note: "Decoupling legislation" refers to states where legislation is in place to support decoupling, but no utilities are decoupled. "Decoupling" refers to states where one or more utilities are decoupled.

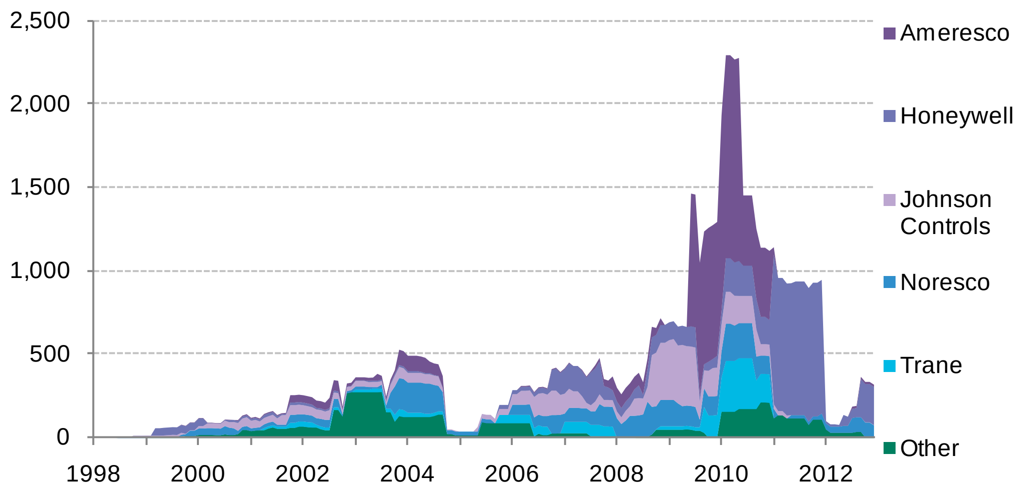
Figure 89: Number of US states adopting EERS, 2000-12



Source: ACEEE, DSIRE, Bloomberg New Energy Finance

At the federal level, the government supports energy services companies by being their most important customer. Bloomberg New Energy Finance estimates that in 2008 the federal government spent $14 on energy performance contracts for every $100 spent on energy. Figure 90 shows the activity in the federal market for energy services – specifically for energy-saving performance contracts. There was a significant peak in the value of contracts signed in early 2010 due to the impact of stimulus money set aside for energy efficiency, followed by a more recent drop-off in the market. Governments can benefit from tax-exempt lease purchase agreements, which in many jurisdictions provide a source of quick finance without the balance-sheet complications associated with some other types of finance.

Figure 90: Value of federal ESPCs executed through the DOE's umbrella agreement, 1998-2011 (total trailing contract value in trailing 12-months, $m)



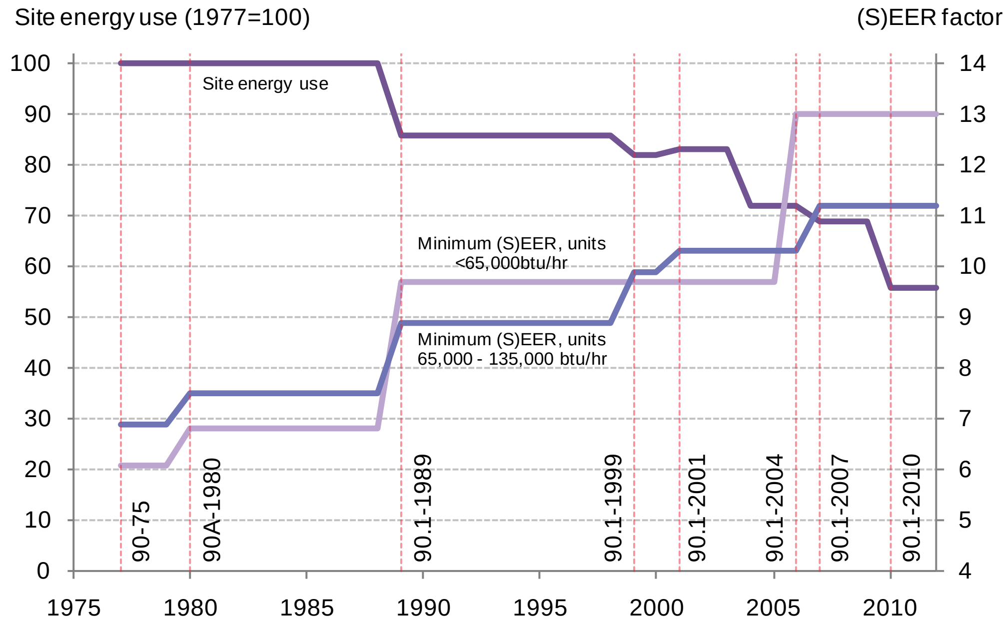
Source: FEMP/DOE, Bloomberg New Energy Finance Note: DOE's umbrella agreement refers to indefinite-delivery, indefinite-quantity (IDIQ) contracts between the DOE and energy service companies. These contracts streamline individual agreements between the company and individual federal agencies.

Building codes and appliance standards

Building codes and appliance standards play an important role in both the deployment of efficient hardware and the improvement of technologies over the course of time. Figure 91 shows how Standard 90 – a standard for building energy efficiency developed by the American Society of Heating, Refrigerating and Air Conditioning Engineers – has evolved since the late 1970s. The standard is plotted in terms of 'site energy use' – an estimate of the energy consumption of a compliant building. In the case of air conditioning this is the energy efficiency ratio (EER), which measures the rate at which a unit cools the air relative to its power consumption. A lower site energy use and a higher EER factor reflect higher efficiency. (In 1989, SEER, the average energy efficiency ratio over an entire year, became the standard metric for air-conditioning standards.)

On average the energy consumption of modern equipment is almost half that of equipment that complied with the standards in 1977. In 1999, the Society's Board of Directors voted that the standard should be put on continuous maintenance, increasing the frequency with which it can be updated, and accelerating the rate at which technology must improve.

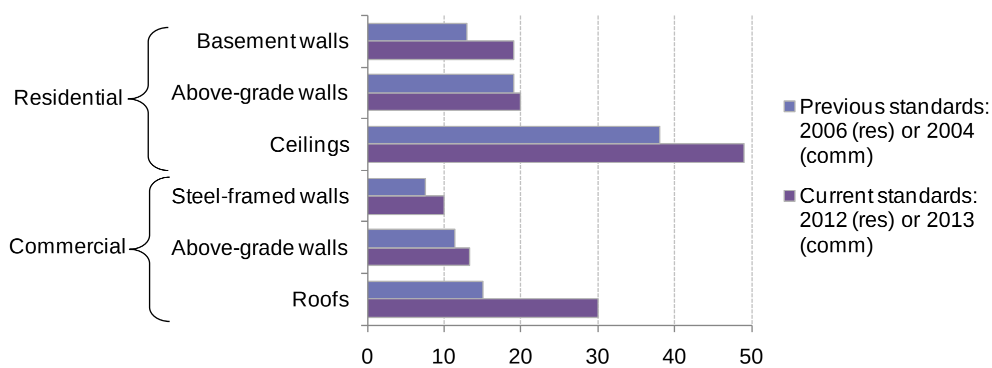
Figure 91: Stringency of ASHRAE Standard 90 in terms of estimated site energy use and air conditioning unit SEER factor, 1977-2012



Sources: Pacific Northwest National Laboratory, Ingersoll-Rand, Bloomberg New Energy Finance. Note: (S)EER stands for (Seasonal) Energy Efficiency Ratio. For standards 90-75 and 90A-1980, minimum standards were defined in terms of EER; from 90.1-1989 onwards SEER was used. ASHRAE is the American Society of Heating, Refrigerating and Air Conditioning Engineers.

The preceding analysis showed the improved standards for buildings' energy use and for heating and cooling systems. Thermal performance – ie, building insulation – is also critical for building energy profiles, and here too the standards have consistently increased. Figure 92 shows the rise in performance standards by 'thermal component placement' (location in the building where the insulating material is placed, such as roofs and walls). The figure shows the increase in one particular 'climate zone' of the country, but similar increases have been realized across other climate zones.

Figure 92: Thermal performance standards by building placement for residential and commercial buildings in Climate Zone 5, 2004/2006-2012/2013 (measured in R-values)



Sources: PIMA (Polyisocyanurate Insulation Manufacturers Association), NAIMA (North American Insulation Manufacturers Association), based on standards from ASHRAE and IECC; Bloomberg New Energy Finance Notes: Counties across the US are grouped by 'climate zones' with similar climate characteristics (heating and cooling degree days). Values shown in this chart correspond to 'Climate Zone 5', which includes regions such as most of Massachusetts, Pennsylvania, Ohio, Iowa, Nebraska, Washington, Oregon, and Nevada. Thermal performance standards as established by ASHRAE and IECC are measured in R-value, a measure *of a component's resistance to the transfer of heat (greater R-value means more resistance - ie, better insulation). For residential values shown on the chart, the previous standards were IECC-2006 standards, and the current standards are IECC-2012. For commercial values, previous were ASHRAE 90.1-2004, current are 90.1-2013. The 2013 ASHRAE standard for commercial buildings has not yet been finalized but is expected to be. Basement walls have two R-values: continuous sheathing and cavity insulation; values shown in this chart correspond to cavity insulation. R-values for steel-framed walls (under commercial) apply to high-rise residential buildings.*

State leadership has been an important driver for improved performance. The role of state energy codes, most of which are based upon adoption of the ASHRAE and IECC standards[3] depicted above, has increased dramatically in the past five years. According to the 2011 Annual Report of the Building Codes Assistance Project, over 30 states have adopted increased thermal performance requirements for commercial buildings and 24 states have done so for residential construction. Pending increases in both ASHRAE and IECC standards will raise these requirements in many parts of the country.

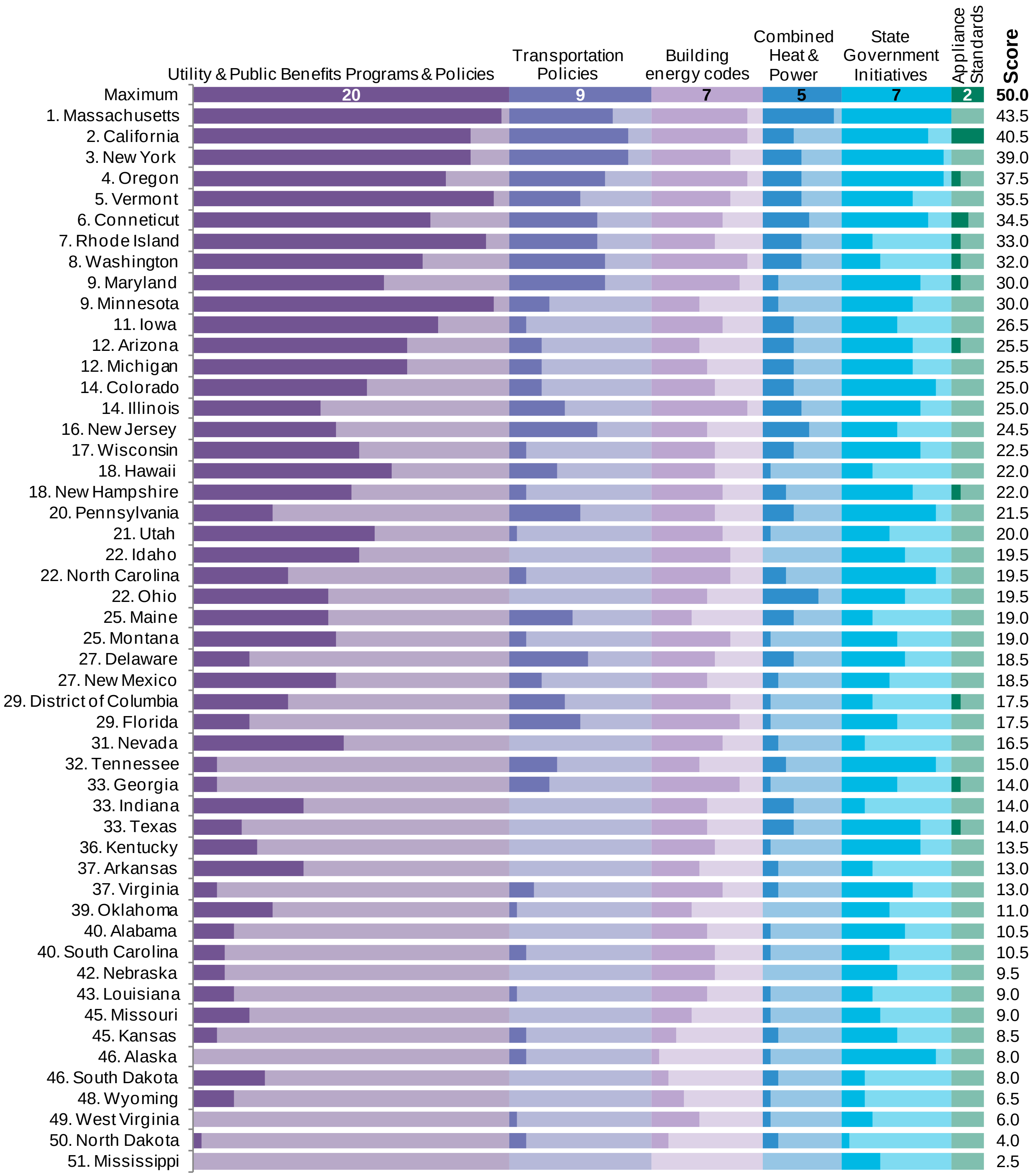
While building codes such as ASHRAE Standard 90, IECC and International Residential Code (IRC) serve as reference points around which lawmakers at a state- or local-level build customized building legislation, *appliance standards* are more typically set at a federal level. Although states originally set their own appliance standards (starting with California in the late 1970s), federal standards were introduced in 1987 under the National Appliance Energy Conservation Act. This had the advantage of preventing a patchwork of standards from emerging – though the disadvantage is that states wanting to introduce more stringent standards are often prevented from doing so: federal standards 'pre-empt' standards at a lower level of jurisdiction, rendering them effectively powerless. (There are exceptions, as states can engage in a waiver process, which has been used on selected occasions.) A recent report by the ACEEE estimates that roughly 80% of the energy associated with appliances and building equipment is covered by federal standards that pre-empt state or local standards. ACEEE has also estimated that the cumulative savings to consumers through 2035 attributable to all appliance and equipment standards will exceed $1.1 trillion.

Comparisons of US states' efficiency policies

To compare the progress made by different states in relation to energy efficiency the ACEEE created a framework for rating the strength of policy positions across a range of areas. The results of the most recent scorecard are shown in Figure 93. California and Oregon have been among the top five states for the past six years. Other leading states include Massachusetts, New York and Vermont.

3 ASHRAE is the American Society of Heating, Refrigerating and Air-Conditioning Engineers. IECC is the International Energy Conservation Code.

Figure 93: ACEEE state-by-state scorecard for energy efficiency policies, 2012



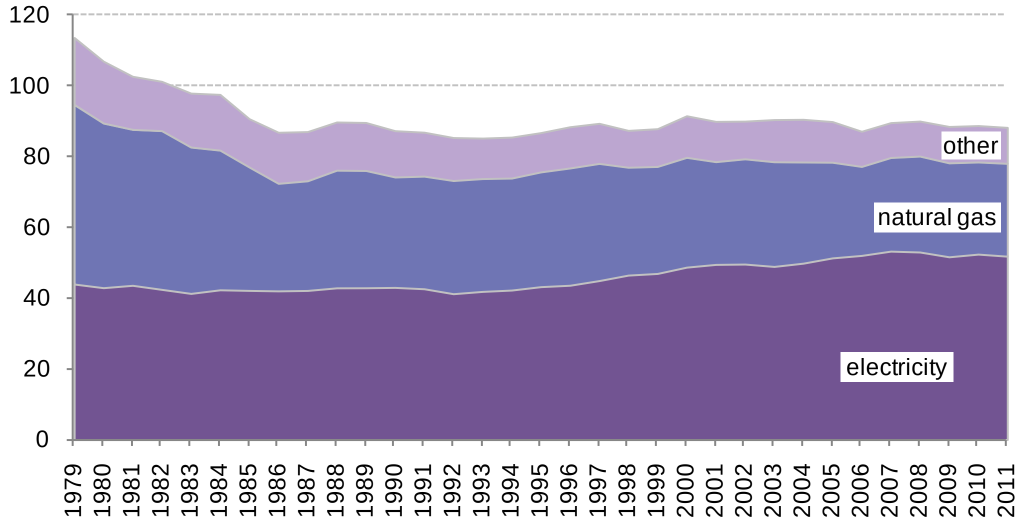
Source: Bloomberg New Energy Finance, ACEEE

Deployment – building efficiency

Tracking deployment of efficient technologies within the building stock is challenging. Deployment consists of numerous unreported decisions and interventions that are individually small but collectively significant. Further, there is ambiguity as to where the line should be drawn between ‘energy efficient’ and ‘business as usual’. Nevertheless, the impact of efficiency deployments can be seen in terms of energy consumption within buildings.

Figure 94 shows how the energy consumption of commercial buildings in the US has evolved since the 1980s. (The chart shows energy intensity, which in this case means energy consumed per unit of building space – a useful measure to track efficiency as the overall building stock grows over time.) Over that period, energy intensity has decreased by over 20%. In addition, electricity intensity of buildings has increased overall, particularly from around 1992 onwards, likely owing to an increase in the number of electricity-consuming appliances within modern buildings. Yet, despite the proliferation of those appliances, this increase has been less than 1% annually. This increase has been partially offset by improvements in ventilation, air conditioning, and lighting efficiency.

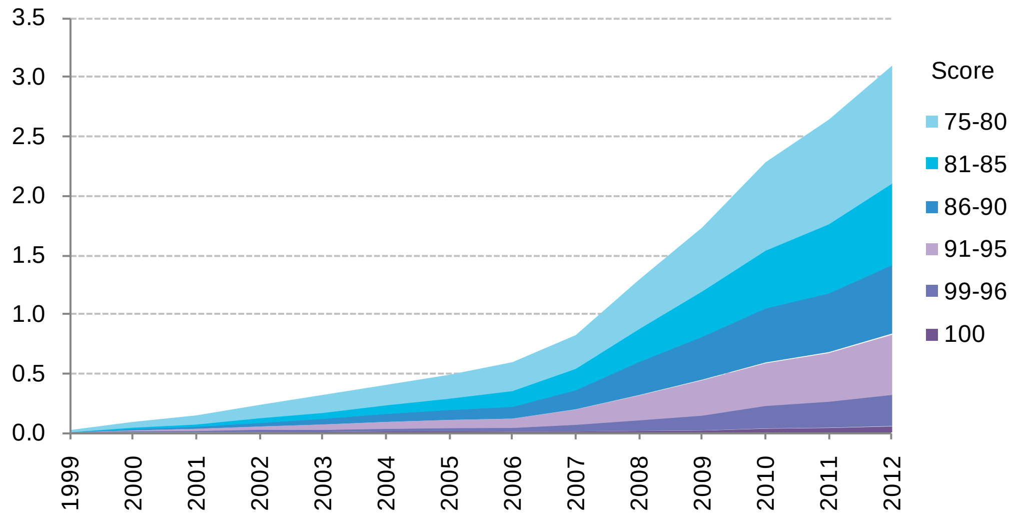
Figure 94: US commercial building energy intensity, 1980-2011 (kBtu/sq-foot)



Source: EIA, Bloomberg New Energy Finance Note: This analysis is based on (i) EIA data on US commercial building energy consumption and floorspace for the years 1979, 1983, 1986,1989, 1992, 1995, 1999, 2003 and (ii) EIA data for total US commercial sector energy consumption for every year between 1979-2011.

Another measure of deployment for energy efficiency in buildings is prevalence of certification schemes. Figure 95 shows the increase in Energy Star-certified commercial floor space since 1999. The rate of certification has accelerated since the mid-2000s to the point that over 3bn ft^2 of floor space are now covered.

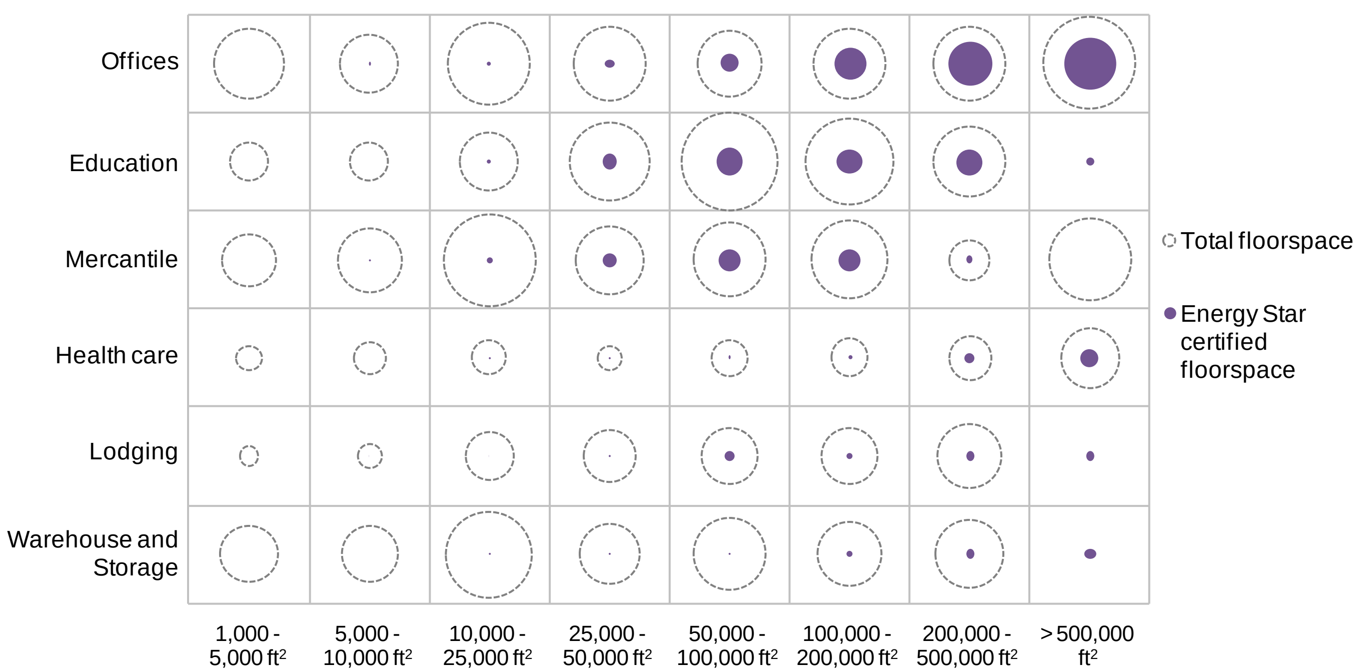
Figure 95: Energy Star-certified floor space in US commercial buildings, categorized by score, 1999-2012 (bn ft^2 of floor space)



Source: US EPA, Bloomberg New Energy Finance

There are particular building profiles in which the rate of Energy Star certification is high – most notably in large offices (Figure 96). Over 30% of office floor space in buildings above 100,000ft^2 in size is now Energy Star-certified. However there are also building profiles for which certification is low: warehouses and storage facilities, lodging and hospitals have very low rates of certification for all but the largest buildings. Buildings smaller than 25,000ft^2 have low rates of certification across all sectors.

Figure 96: Energy Star-certified floor space and total floors space for US commercial buildings, segmented by sector and building size



Source: US EPA, EIA, Bloomberg New Energy Finance. Note that data is lacking for total US floor space of warehouses, lodging and educational buildings with floor space in excess of 500,000ft^2.

The industry for energy services companies has grown substantially over the past two decades. Lawrence Berkeley National Laboratories estimates that revenues from performance contracting were less than $500m in 1992, exceeded $1bn in 1995, exceeded $2bn in 2000 and exceeded $4bn in 2008. The bulk of this revenue (~70%) has been generated from state and local governments which have been able to take advantage of a framework, known as the tax-exempt lease purchase (TELP), to finance such projects off-balance sheet.

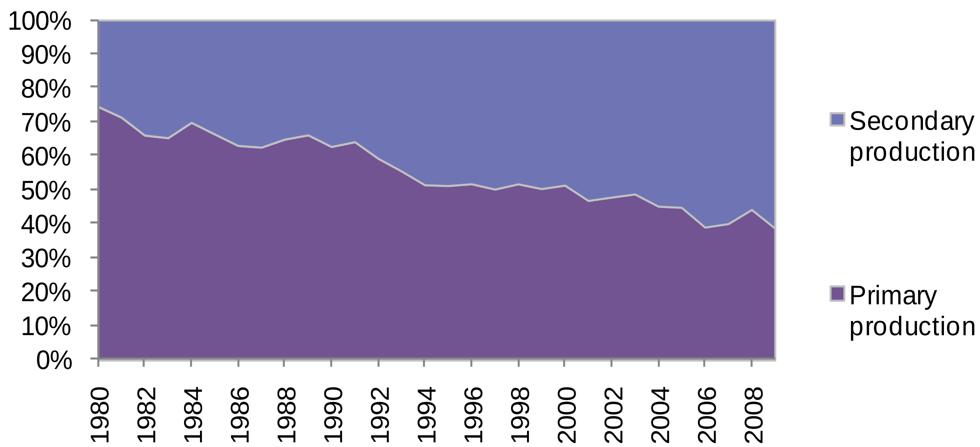
Finally, while much of the ground covered in this section focuses on *electricity* use in buildings, direct use of natural gas bears mention, given the relatively high efficiency of conveying this energy to users. From wellhead to consumer, 92% of natural gas produced is ultimately delivered as usable energy; as a comparison, in the case of coal, that efficiency metric is 32%.

Deployment – industrial efficiency

US aluminum serves as a useful case study to evaluate deployment of efficiency in the industrial sector. Aluminum production requires more electricity than any other manufactured product; the US aluminum industry is responsible for 1.2% of all electricity consumed in the US.[4] Recycling and the efficient use of produced aluminum can thus result in significant energy savings.

Recovery from scrap metal consumes just 5% as much energy as producing new aluminum. This ultimately improves the lifecycle sustainability and lowers energy intensity of aluminum products, and goods made with those products. Due to this economic benefit of recycling, in 2009 61% of aluminum was made in the US via secondary production (ie, 61% of new aluminum was produced by recycling aluminum, which can come from post-consumer and industrial scrap) (Figure 97).

Figure 97: US primary vs secondary aluminum production



Source: Bloomberg New Energy Finance, US Geological Survey

Changing consumer behaviour has also spurred increased aluminum recycling. More consumers have actively made the effort to recycle beverage cans. In 2011, 65% of aluminum cans produced were recycled, up from 50% in 2003 (Figure 98).

4 US DOE, US Energy Requirements for Aluminum Production, February 2007

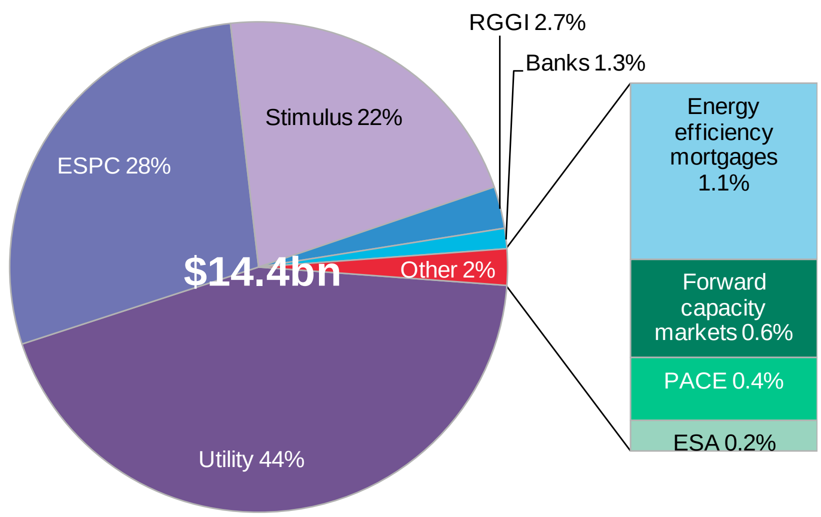
Figure 98: US aluminum cans collected for recycling and % of total cans collected

Source: Bloomberg New Energy Finance, The Aluminum Association, Inc, Can Manufacturers Institute, Institute of Scrap Recycling Industries, Inc.

Financing

Figure 99 shows the share of various finance channels for energy efficiency in the built environment. Direct energy efficiency investment by utilities, typically as a part of the energy efficiency resource standards (EERS) described above, account for the majority of investment. This is followed by energy-savings performance contracting (ESPC) through the energy service company business model (Figure 99).

Figure 99: US energy efficiency expenditure by mechanism, 2010 ($bn)



Sources: DOE, CEE, LBNL, PJM, ISO-NE, Bloomberg New Energy Finance. Notes: ESPC (Energy Savings Performance Contracts) revenue projected from 2008."Stimulus" dollars represent strictly energy efficiency retrofit dollars from various programs. RGGI stands for Regional Greenhouse Gas Initiative. PACE stands for Property Assessed Clean Energy. ESA stands for Efficiency Service Agreements.

Financing building retrofits in the commercial sector remains challenging for a variety of reasons, including agency issues, short-term horizons for building use, and the balance-sheet impact of efficiency investments. The past five years have seen considerable innovation in this area, with different financing mechanisms being proposed. There are two worth noting:

1. Property assessed clean energy (PACE) aims to resolve agency issues by pushing repayments for building retrofit finance onto a building's property tax bill and has gained some traction in the small number of municipalities that have so far administered such a scheme.
2. Efficiency service agreements are a way of financing energy-savings performance contracting in which the user pays on a per-kWh-saved basis rather than through a more conventional loan or lease agreement. The agreement is essentially equivalent to a lease but the obligation to pay for kWh saved – rather than fixed dollar payments – could be treated differently by accountants, allowing the arrangement to be taken off-balance sheet. The accounting treatment of efficiency service agreements is currently the subject of debate.

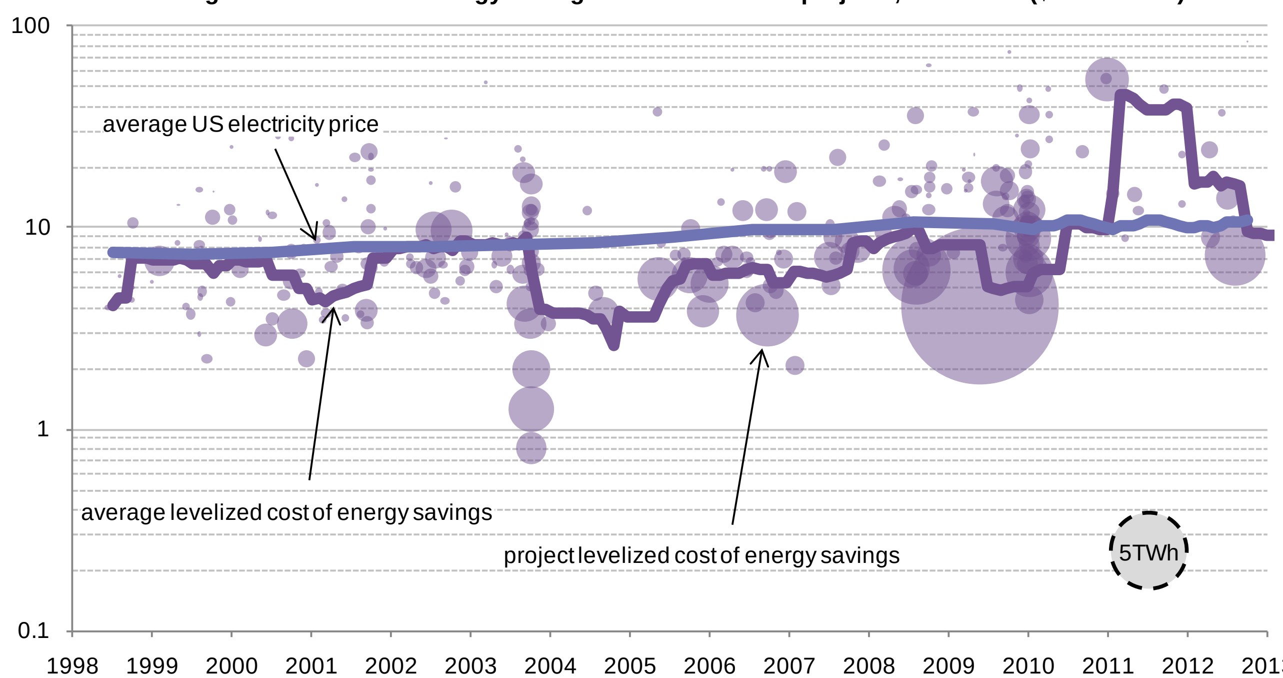
These innovative approaches for funding energy efficiency are evidence of a maturing industry.

Economics

The cost of saving a kWh of energy is difficult to define. The estimated cost depends on the energy-saving measures being deployed, investment framework, and method used to quantify the energy savings. A representative range for the cost of certified savings under EERS programs is $0.03-7/kWh (though there are extreme cases that lie far outside of this). This is cheaper than the residential tariff of the energy being saved (which averages $0.12/kWh in the US).

Figure 100 shows the LCOE savings for federal energy-savings performance contracting projects compared with the retail price for electricity. For most projects, the cost of saving energy is less than the retail price of electricity, but not always. In such cases, the price of the energy being saved may have been particularly high but it is more likely that other considerations were at play, such as using energy savings to fund the replacement of aging equipment, to increase comfort levels, or to subsidize the implementation of on-site renewable generation.

Figure 100: LCOE savings and discounted energy savings for federal ESPC projects, 1998-2013 ($ cents/kWh)



Source: FEMP, Bloomberg New Energy Finance. Note: Bubble size represents discounted lifetime project savings. Discount rate of 5% used. Average levelized cost of energy savings calculated using from contracts signed in preceding 12 months. Project year corresponds to year the contract was signed. Each bubble denotes an individual contract.

Market dynamics

Companies such as Johnson Controls, Ingersoll-Rand, Ameresco, Honeywell, Noresco, Trane and Chevron Energy Solutions are all leaders within the field of energy services – a sector that has grown substantially in the past decade. For utility-funded energy efficiency, the key players tend to be the utilities themselves, appliance manufacturers and local installers.

6.2. Smart grid and demand response

Policy

Smart grid infrastructure includes smart meters, distribution automation, smart transmission devices (such as synchrophasors and dynamic thermal line rating technology) and smart home technologies, as well as integrated projects across these segments. For the smart grid industry, the first supportive policy came in the Energy Policy Act of 2005, which required that all states conduct proceedings to look into smart meters and time-based pricing. The single largest policy boost was the 2009 American Recovery and Reinvestment Act stimulus package, which provided $4.5bn in project grants for more than 100 smart grid projects and pilots across the country. This support has been augmented by state regulators and municipal governments approving investments at the local level.

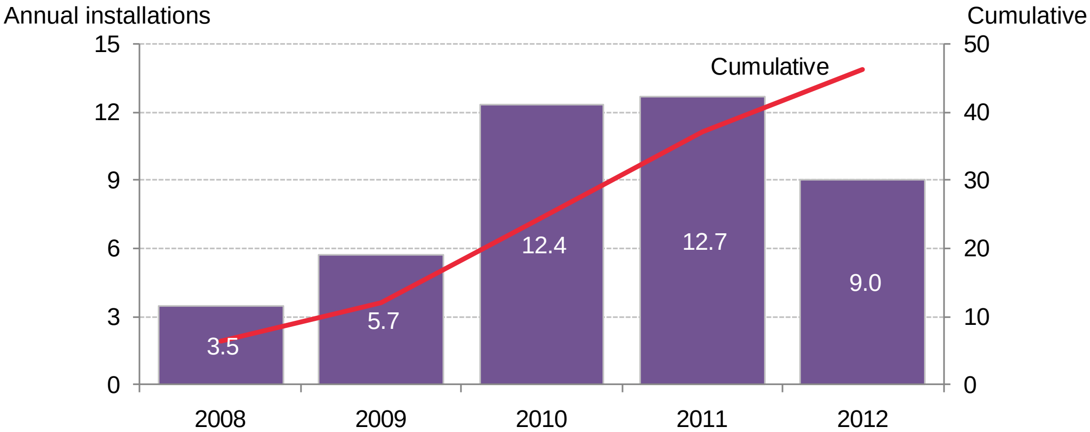
Demand response capacity typically involves the curtailment of electricity consumption, usually at times of peak usage; the consumer whose load is being curtailed is generally offered compensation for this service ('incentive-based'). Alternatively, the response can also involve the application of on-site generation, reducing stress on the grid, though some counter whether this truly qualifies as efficiency. Another form of demand response (known as 'price-based') involves applying time-varying power prices to customers via smart meters, who can then adjust consumption accordingly.

Growth in the demand response sector was stimulated by FERC’s insistence that these resources be included in wholesale markets operated by regional transmission organizations (RTO) and ISOs. This new market gave rise to a new group of demand response providers which, with the encouragement of state regulators, began to offer retail demand response via utilities. In addition, three decisions by FERC have further bolstered the standing of demand response: Order 745, which calls upon operators of wholesale electricity markets to allow demand response resources to be compensated fully in energy markets (ie, a kWh turned off should receive equal payment as a kWh turned on); the earlier Order 719, which addresses ancillary services; and most recently Order 755, which rewards fast-acting resources like demand response and energy storage in regulation markets. Finally, at least in the case of Texas, deregulation/restructuring policy allowed demand response products to be offered in a competitive retail market environment. State policy on demand response and smart grid is reviewed each year by the Association for Demand Response and Smart Grid.

Deployment

The first segment of US utilities to adopt smart meters was the rural electric cooperative sector (though these early deployments did not have some of the 'smart' features of meters being deployed today, such as intervals for dynamic pricing). In the late 2000s, a number of investor-owned utilities, primarily in California, made the first large moves to install smart meters across their service territories. This was followed by a larger wave of utilities across the country following suit and increasing investments in smart meters, communication networks, distribution automation and associated software upgrades. By the end of 2012, over 46m smart meters were deployed in the US, according to Bloomberg New Energy Finance's project database (Figure 101). The market peaked in 2011, with 12.7m smart meters deployed in that year, up from just 3.5m in 2008.

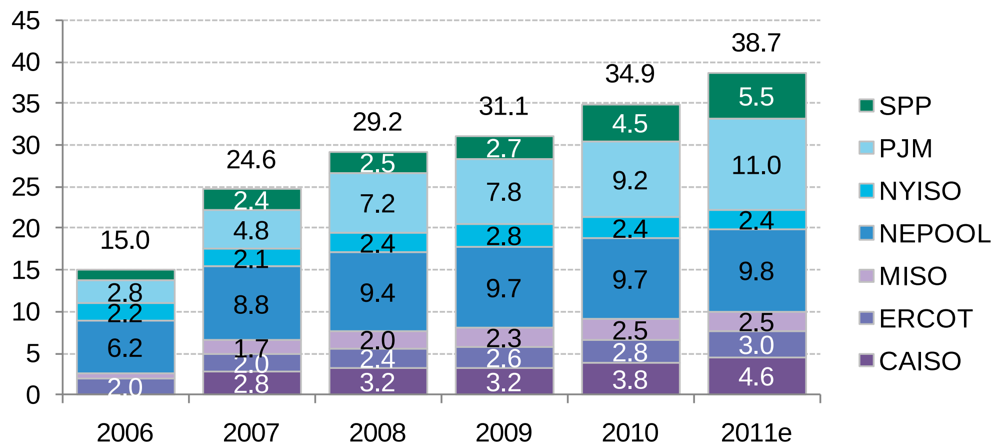
Figure 101: US electric smart meter deployments, 2008-12 (m units)



Source: Bloomberg New Energy Finance Note: Based on study of 315 US smart grid / metering projects.

As for demand response, capacity growth has been strong over the last six years, driven in particular by programs in the ISO/RTO markets.[5] Incentive-based demand response capacity in these markets (ie, resources that are compensated for curtailments, as distinct from price-based demand response) grew rapidly from 15GW in 2006 to around 39GW in 2011 (Figure 102). PJM, ISO-New England and the New York ISO are viewed as three of the most proactive markets for promoting demand response, and their respective capacity market programs have been particularly successful in stimulating demand-side participation.

Figure 102: Incentive-based demand response capacity by US ISO/RTO, 2006-11e (GW)



Source: Bloomberg New Energy Finance, data from ISOs. Note: 2011 figures are estimates. These figures include demand response activity driven by customer curtailment, as well as by behind-the-meter generation, since the ISOs do not provide this break-out.

A separate analysis, conducted by FERC and based largely on results from a survey, estimates that the *potential* demand response contribution from all US programs (incentive-based and other) is at

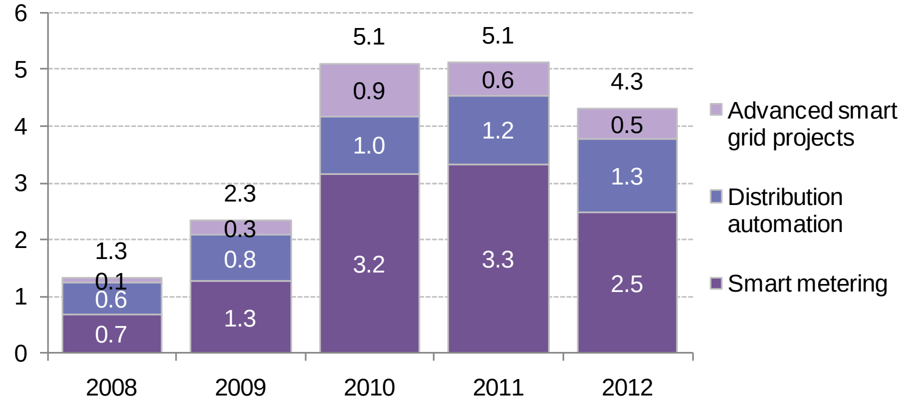
5 ISO/RTOs refer to independent system operators and regional transmission organizations. These are entities that operate wholesale electricity markets in certain regions of the country. Among other services, ISOs and RTOs facilitate competition by ensuring that even non-utility companies (such as demand response providers) have equal access to deliver into the grid.

nearly 72GW, or 9.2% of US peak demand, and an increase of 13GW from its 2010 analysis (as per the Commission's 2012 Assessment of Demand Response & Smart Metering).

Financing

Federal support and state-level approvals led to explosive growth in smart grid spending through 2010-11, reaching $5.1bn in 2011 as stimulus-funded projects got underway (Figure 103).

Figure 103: US smart grid spending by segment, 2008-12 ($bn)



Source: Bloomberg New Energy Finance. Note: The 'advanced smart grid' category includes projects that are cross-cutting, including elements such as load control, home energy management and EV charging.

With stimulus programs near completion, 2012 saw smart grid investment levels begin to tail off. While they remained high – $4.3bn in 2012, with nearly 10m smart meters deployed last year – they have not matched the highs of 2010-11, when the stimulus-funded projects were in full swing.

Economics

The business case for smart grid investment differs widely between utilities, and typically consists of an array of different types of benefit. For consumers, benefits include more accurate energy bills, better knowledge of their actual consumption habits, and the ability to benefit from demand response and energy management programs that help them manage and reduce bills. For utilities, operational savings such as reduced meter reading, outage management, and customer service are the most immediate value driver. Smart grid technologies introduce sensory, control and management capabilities that allow an increase in reliability and better resiliency when the grid is harmed.

Smart grid technologies are also necessary to enable demand response, with the smart meter being the best example. Key to demand response is being able to measure when electricity is used or shifted, something only possible with a smart meter. Demand response also figures into utility business cases. Smart grid technologies, and the demand response they allow, further provide the benefit of enabling large amounts of intermittent and variable wind to come onto to the grid. Demand response can be quickly dispatched when such renewable resources are not available

Despite the broad array of benefits, and a strong history of recent projects in the US, smart grid business cases can still be contentious, often due to the challenges with quantifying the customer benefits of these investments and the issue of benefit leakage and spillage between states and regions.

For demand response, revenues are dominated by payments from the capacity markets (as opposed to payments from the energy markets), because reliability services are more valuable than providing energy during peak electricity events. Revenues from ancillary services comprise another portion of the revenues. Together, capacity and ancillary service revenues range between $40,000 and $80,000/MW/year, depending on factors such as location and level of competition.

Market dynamics

The five major providers for smart meters in the US are Landis+Gyr, GE, Itron, Sensus, and Elster, which collectively account for almost all of the disclosed smart meter contracts awarded so far. Silver Spring Networks, a privately held company that has indicated its intentions to go public, is the leading player in the market for smart grid communication infrastructure. Although the market is highly competitive, cooperation between vendors is also very common. This is because utilities' unique requirements often call on companies like Landis+Gyr (which is owned by Toshiba) to integrate their meters with communications equipment from companies like Silver Spring Networks – even though Landis+Gyr and other meter manufacturers also offer their own communications solutions.

The same dynamics can also be seen in the meter data management software business, where cooperation has led to consolidation. Two examples are eMeter and Ecologic Analytics, which were acquired by Siemens and Landis+Gyr respectively. Beyond roll-outs of smart meters and implementation of communication infrastructure, other investment areas in the smart grid industry include distribution automation, home area networks, and smart grid analytics software. The latter two are still in the early stages of development. Investments in distribution automation have focused on the areas of fault location, isolation, and restoration (FLISR); asset management; and volt-VAR optimization. Home area network deployments include in-home displays, smart thermostats, smart appliances, and other load control devices. Smart grid data management and analytics software have already attracted the attention of industry giants such as Oracle and SAP, as well as a growing crowd of start-up companies.

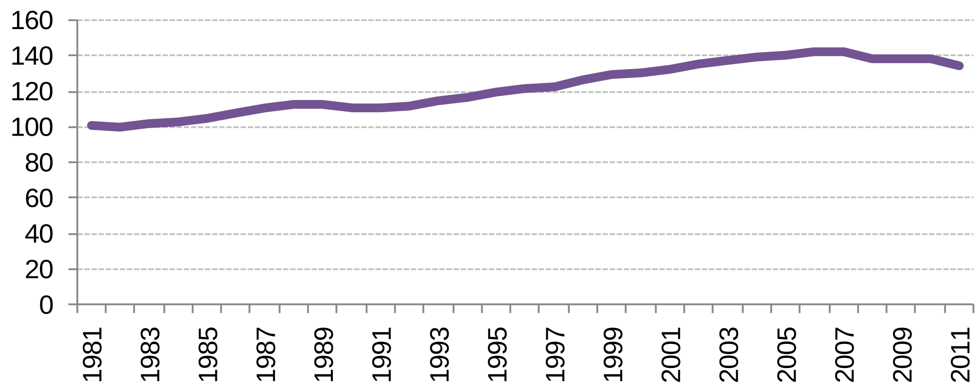
A final but important development for the smart grid industry has to do with its role in enhancing infrastructure resilience; investments in smart grid have been a feature of policy discussions in the aftermath of Hurricane Sandy.

For demand response resources, both ancillary services and energy markets are being opened up to complement the existing capacity markets, and recent and upcoming regulatory action has the potential to create more opportunities for demand response in wholesale energy, frequency regulation and reserves. Major providers of demand response in the US include EnerNOC, Comverge, Constellation Energy, Energy Curtailment Specialists, Johnson Controls, Honeywell, Schneider-Electric, and Viridity Energy.

SECTION 7. SUSTAINABLE ENERGY TRANSPORTATION

The country's ground transport sector is undergoing its own transition prompted by a mix of policy, cheap domestic gas and technology innovation. Corporate average fuel economy (CAFE) standards call for increasing efficiency of US light-duty vehicles by 99% by 2025, relative to 2011 averages. Hybrids, plug-in electrics, and natural gas vehicles (NGVs) are growing in prominence; sales for the first two reached 488,000 vehicles in 2012 (3.25% of US passenger vehicle sales), and natural gas demand from the transport sector increased by 26% from 2008 to 2011. In addition, a number of major automakers are aiming for commercial roll-out of fuel cell electric vehicles (FCEVs) by 2015. These factors, along with a growing role for ethanol-derived fuels, are driving gasoline consumption down from its 2007 peak.

Figure 104: US gasoline consumption, 1981-2011 (bn gallons)



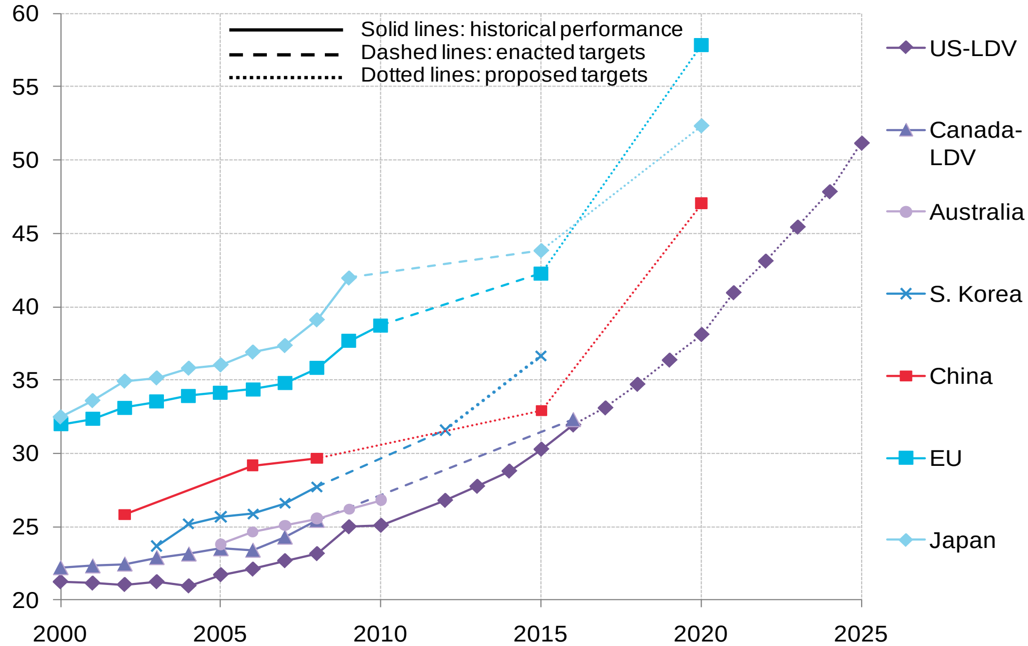
Source: Bloomberg New Energy Finance, EIA Note: The above data denotes gasoline supply, which is used to approximately represent consumption.

7.1. Electric vehicles

Policy

Supply and demand for hybrids and electric vehicles have benefited from various policy mechanisms. While the US has traditionally trailed Europe and Japan in setting high fuel economy standards, in 2012 the federal government reached a landmark agreement with auto companies that will bring the US CAFE standard closer to that of Europe and Japan by 2025 (Figure 105).

Figure 105: Fuel economy standards for US light-duty vehicles relative to other countries, 2002–25e (mpg)



Source: International Council for Clean Transportation, Bloomberg New Energy Finance. Note: Figures are normalized to New European Driving Cycle, which is a combination of city and highway cycles. LDV stands for light duty vehicles.

Far stricter than the CAFE standards, California's Air Resources Board's Zero Emission Vehicle (ZEV) program has been inducing auto manufacturers since 1990 to produce a certain quota of alternative vehicles (eg, fuel cell, hybrid and battery electric vehicles) for sale in California. Though the ZEV program has been controversial, it has had a lasting impact on the market availability of alternative vehicles.

While CAFE and ZEV act as sticks, both federal and state governments have also offered carrots to induce both manufacturers and consumers to adopt alternative vehicles. The Energy Independence and Security Act of 2007 authorized $25bn of loans from the US Treasury to fund manufacturing of high-efficiency and low-emission vehicles and vehicle components. Thus far the Treasury has lent over $8.3bn to recipients such as Ford Motor, Nissan North America, Tesla Motors, and Fisker Automotive. The American Recovery and Reinvestment Act of 2009 further expanded grants and loan programs available for investment in the production of advanced vehicles and related components in addition to deployment of refuelling and charging infrastructure: as part of the stimulus package in 2009, the Department of Energy awarded 48 grants totalling $2.4bn through the Electric Drive Battery and Component Manufacturing Initiative.

To support demand for electric vehicles, the federal government has also provided tax credits, starting at $2,500 for a vehicle with a 4kWh battery, and increasing by $417/kWh to a maximum of $7,500. The credit begins to phase out on a per-manufacturer basis when that manufacturer's sales of qualifying vehicles reach 200,000. There are also complementary state-level incentives to purchase electric and hybrid vehicles and associated refuelling infrastructure.

For fuel-cell powered vehicles, the 2005 Energy Policy Act authorized credits for vehicles using alternative fuels, including qualified fuel cell electric vehicles, as shown below:

- Light-duty fuel cell electric vehicles (under 8,500lb, usually passenger vehicles) placed in service after 31 December 2009 may receive a credit of up to $4,000
- Medium-duty models (8,500-14,000lb) placed in service after enrolment of the Act may receive a credit of up to $10,000
- Medium-heavy duty fuel cell electric vehicles (14,000-26,000lb) placed in service after enrolment of the Act may receive a credit of up to $20,000
- Heavy duty ones (over 26,000lb) placed in service after enrolment of the Act may receive a credit of up to $40,000

In addition, vehicles can increase these credits by $1,000-4,000 per vehicle if they achieve a fuel economy far exceeding the 2002 model year city fuel economy. Under current law, this tax credit expires on 31 December 2014.

Federal and state governments have established a policy framework to support these technologies via promoting development of hydrogen delivery infrastructure. Specifically, the US Department of Energy has adopted a technical roadmap to reduce the cost of hydrogen delivery from the point of production to the point of use to a price point below $3/gallon of gasoline equivalent by 2015 and below $2/gallon of gasoline equivalent by 2020. In addition, the Hydrogen Vehicle Refueling Property Tax Credit provides a credit of up to 30% of hydrogen refueling property, not to exceed $30,000. Under current law, this tax credit expires on 31 December 2014. California's Clean Fuels Outlet Regulation mandates that major refiners or importers of gasoline provide hydrogen fueling when 10,000 fuel cell electric vehicles are on the roads in a particular air basin.

In Hawaii, a public-private partnership, the Hawaii Hydrogen Initiative (H2I), plans to install 20-25 hydrogen stations around Oahu. H2I includes state, local and national partners, including the military, and is based on an agreement between General Motors and Hawaii Gas.

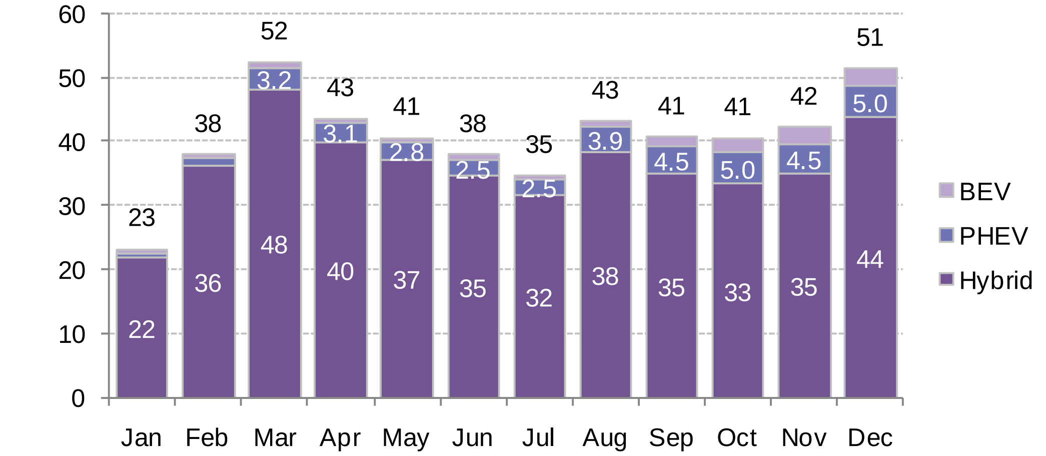
Finally, MAP-21, the 2012 Federal Surface Transportation Law, includes authorizations for a zero-emission bus deployment program, which includes fuel cell electric buses and hydrogen infrastructure.

Deployment

2011 was dubbed the year of the electric vehicle (EV) with the global commercial launch of mass produced plug-in hybrid (PHEV) and pure battery-powered (BEV) electric vehicles. While sales in 2011 remained below initial targets of auto manufacturers, 2012 has seen steady increases in EV sales as more models have become available. Additionally, (non-plug-in) hybrid vehicles have gone mainstream from being a niche segment just a few years ago, with well-known models (eg Toyota's Prius line-up) dominating passenger vehicle sales across the globe.

At the end of 2012, the US passenger vehicle market included 44 hybrid models, eight BEV models and four PHEV models. The contribution of last two was modest at the beginning of the year, yet by year-end, total annual sales figures over the 12 months for these two types had climbed to 53,172 vehicles – almost three times that of total EV sales in 2011. Among the PHEVs and BEVs, leading models were Chevrolet Volt at 23,461 units, followed by Toyota Prius PHV at 12,749 and Nissan Leaf at 9,819 units. Hybrid vehicle sales also increased compared to 2011. Since February the hybrid segment has consistently posted monthly sales above 30,000 units. 2012 total hybrid sales were 434,647 units – a 61% increase compared to 2011.

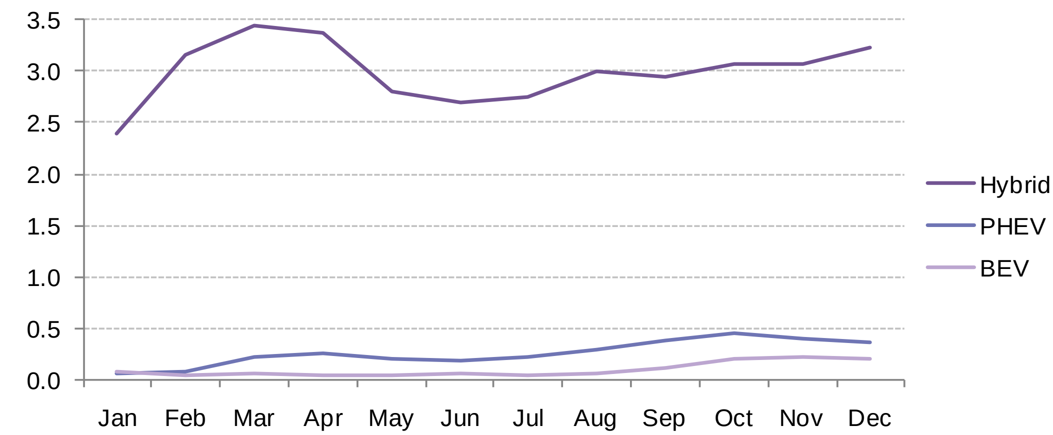
Figure 106: US passenger hybrid, plug-in hybrid and battery electric vehicle sales, 2012 (thousand units)



Source: Bloomberg New Energy Finance

As a percent of total US 2012 passenger vehicle sales, hybrids are 2.99%, PHEVs 0.26%, and BEVs 0.09% (Figure 107).

Figure 107: Uptake of hybrid, plug-in hybrid and battery electric vehicles as percentage of total US passenger vehicle sales, 2012 (%)



Source: Bloomberg New Energy Finance

While US BEV and PHEV sales may seem modest, the uptake of EVs has also been far faster than the initial introduction of hybrid vehicles in US. It took hybrid vehicles over five years to reach the same level of market penetration that EVs have reached in less than three years from market introduction. Additionally, the US has cemented its position as the world's largest EV market and has the widest selection of mass-produced BEVs and PHEVs.

Passenger fuel-cell powered vehicles are currently not widely available. However, major auto manufacturers have demonstration programs underway with targets for commercialization by 2015 (Table 6).

Table 6: Fuel cell vehicle plans of major auto companies

Manufacturer	Fuel cell vehicle fleet status	Indication of planned activity to 2015
Daimler AG	240 cars in US, Germany, Japan, Singapore	500-1,000 FCVs by 2015
Ford Motor Company	30 from 2004-09 in the US, Canada and Europe	Unlikely to commercialize by 2015(1)
General Motors Corporation / Opel	115 Chevrolet Equinox FCVs in US	Next generation fuel cell vehicle to be commercialized in 2015
Honda Motor Co	~50 FCX Clarity cars leased in California, Japan & Europe	200 vehicles by 2013, 1000 by 2015, commercialization in 2015
Hyundai Kia Automotive Group	80 vehicles in Korea (50 Seoul, 30 Ulsan)	1000 FCVs/year from 2012 up to 10,000/year by 2015
Renault SA & Nissan Motor Co (alliance)	~20 X-Trail FCVs	Nissan aiming to launch FCVs by 2015. In April 2011 it disclosed it was discussing FCV cooperation with Daimler
Toyota	Not Available	Several hundred FCVs by 2013. Commercial introduction in 2015

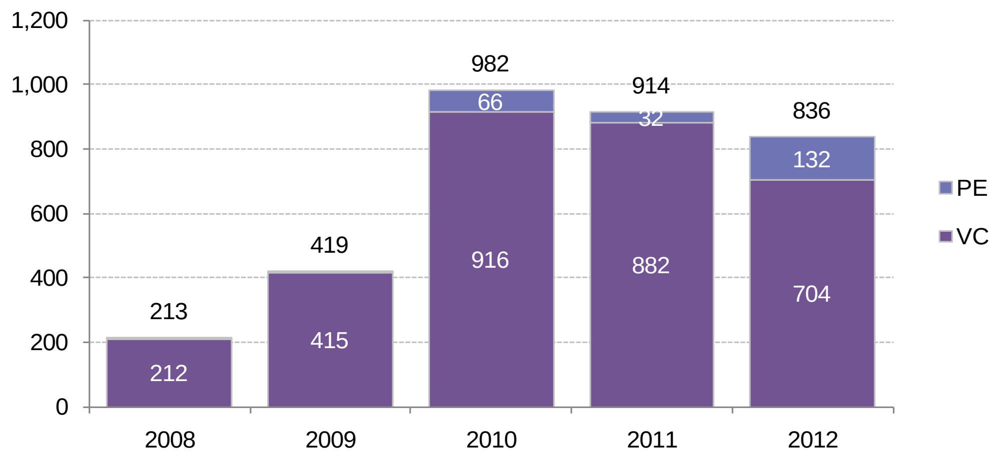
Source: Company data, news stories, analyst estimates, Bloomberg New Energy Finance Note: FCV is fuel cell vehicle. (1) Regarding Ford's planned activity, the company states on its website that "the cost and durability of the fuel cell system [mean the] challenges remain too significant to allow for the commercialization of FCVs at this point, even with the incremental improvements in current state-of-the-art fuel cell technology"

While passenger fuel-cell powered vehicles are in development phase, fuel-cell powered material handling equipment (eg, forklifts) has already achieved initial market success. By the end of 2011, there were already over 3,000 fuel-cell powered forklifts in the US and that number is expected to have reached over 7,000 by the end of 2012. The leading supplier has been Plug Power which relies on proton-exchange membrane fuel cells stacks supplied by Ballard Power Systems. Leading customers of Plug Power include large warehouse owner/operators such as Walmart and Proctor & Gamble. Through the American Recovery and Reinvestment Act, the US DOE has also provided funding to support deployment of fuel cells in other non-road transportation applications (eg, baggage tow-tractors at airports).

Financing

Over the last five years, venture capital and private equity firms have invested over $3bn of private capital in the US clean transportation sector (Figure 108).

Figure 108: Venture capital / private equity funds raised by US EV firms($m)



Source: Bloomberg New Energy Finance. Note: BEV, PHEV, Hybrid, and FCEV, and related infrastructure companies are included. Values include estimates for undisclosed deals.

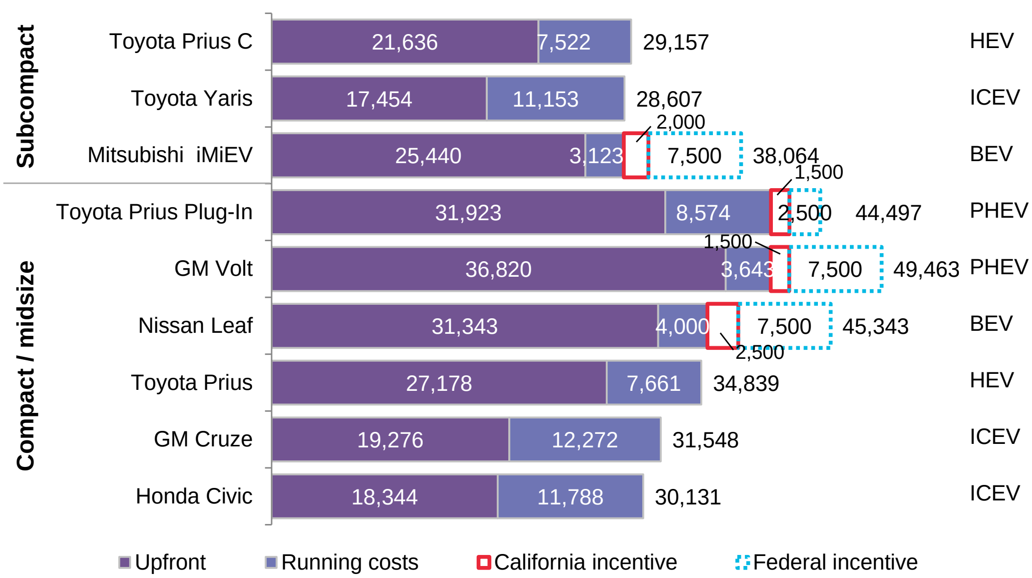
Notable funding beneficiaries have been PHEV manufacturer Fisker Automotive, battery swapping pioneer Better Place, commercial EV manufacturer Smith Electric and EV start-up CODA Automotive. One start-up that has successfully transitioned from venture capital to the public markets has been Tesla Motors. The California-based company raised $260m via an IPO on the Nasdaq in June 2010.

Economics

Currently, hybrid and electric vehicles have higher initial costs compared to an internal combustion engine vehicle in the same class. For hybrids, the initial cost premium is countered by improved fuel economy. Depending on the driving characteristics of the owner, the total cost of ownership of a hybrid vehicle is already close to, if not lower than, an internal combustion vehicle in the same class (Figure 109). For PHEVs and BEVs, the cost premium remains significantly higher and as such total cost of ownership may not yet be competitive for the average US driver.

Yet these economic comparisons have limitations. Some market research indicates early adopters of these hybrids and electric vehicles are choosing these instead of luxury vehicles, which improves the comparative economics for the advanced vehicles. Furthermore, the coming years will see even more choices come to market, introducing great variety in vehicle classes and price points.

Figure 109: Total cost of ownership of select vehicles in the US ($)



Source: Bloomberg New Energy Finance. Note: Upfront cost is after federal and California subsidies, and includes taxes, registration and delivery charges, as well as EV charging equipment where necessary. California and federal incentives are shown to illustrate what TCO would be without them.

Table 7: Basic assumptions for total cost of ownership analysis

Assumption	Value
Annual driving distance	10,100 miles
Daily driving distance	27.7 miles
Discount rate	5%
Life of vehicle	12 years

Source: Bloomberg New Energy Finance

Market dynamics

The clean transportation sector presents opportunities and challenges to both incumbents and newcomers. Established auto manufacturers have adopted widely differing technology strategies. Beyond technology, market dynamics also remain susceptible to shifts in policy and consumer behaviour. To ensure their success, established players and new start-ups continue to rely on partnerships to share risk and investments cost; Table 8 shows a selection of established auto companies' EV strategies and partnerships.

Table 8: EV plans of major auto companies

Company	EV plans	Battery and EV component production
Daimler	• Third edition Smart EV in 2012 • Small quantity production of Mercedes SLS e-drive from 2013	• Joint venture with Evonik: li-Tec • Joint venture with Bosch for EV motor production: EM-motive
BMW	• Developing the i3 as the first mass-produced BEV in 2013, followed by the i8 PHEV in 2014	• Strategic partnership with SB LiMotive (under dissolution) • Joint venture with PSA Peugeot Citroen for EV powertrain components
Volkswagen	• Four Audi models • Up E-motion due in 2013 and E-Golf in 2014	• Batteries supplied by Panasonic
Nissan - Renault	• Leaf in production, and plans to launch the e-NV200 commercial van in 2013 and an Infiniti EV in 2014. • By the end of 2012, Renault will have four EV models: Fluence, Kangoo, Twizy and Zoe • Aims to have annual production capacity for 500,000 vehicles by 2016	• Battery joint venture with NEC – AESC • Batteries supplied by LG Chem for Renault Twizy and Zoe
PSA Peugeot Citroen	• Sells rebadged Mitsubishi i-MiEVs	• Joint venture with BMW for EV powertrain components
Toyota	• Launched Prius Plug-in in February 2012 with continued market expansion throughout the year • Limited production (2,600) of RAV4 EV and iQ Scion (1,100)	• Batteries supplied by Panasonic for Prius • Tesla supplies battery packs for RAV4 EV, with cells originally from Panasonic
Hyundai / Kia	• Limited production of the BlueOn and Kia Ray from 2012 as a trial • Next generation EV planned for launch in 2014	• Battery supply from LG Chem and SK Innovation
GM	• Continued production of Chevrolet Volt • Launch of Chevrolet Spark EV in 2013	• Batteries from LG Chem for the Volt, A123 for the Spark EV and Hitachi Vehicle Energy for Buick micro-hybrids • New plant for EV motor production online in 2012
Ford	• Ford Focus Electric rolled out in 2012 • Launch of Fusion Energi PHEV in 2012 and C-Max Energi PHEV in 2013	• Battery supply from LG Chem for Focus Electric • Battery supply from Panasonic for hybrids
Mitsubishi	• Continued production of i-MiEV and i-MiEV Minicab • Will launch a PHEV version of the Outlander in 2014	• Battery joint venture with GS Yuasa – Lithium Energy Japan • Secondary supply from Toshiba
Honda	• Fit/Jazz EV launch in 2012 • Accord Plug-in launch in late 2012	• Battery joint venture with GS Yuasa for HEV and PHEV – Blue Energy • Secondary supply from Toshiba for BEV

Source: Bloomberg New Energy Finance, company reports

7.2. Natural gas vehicles

Policy

The federal government provides some level of support, in the form of tax-based and other subsidies, to promote natural gas vehicle use. Compressed natural gas (CNG) and liquefied natural gas (LNG) qualify as 'alternative fuels' under the Energy Policy Act of 1992.

Tax incentives include those that can be applied to capex (eg, 30% tax credit, up to $30,000, for installation of fuelling equipment; or $1,000 tax credit for residential versions) as well as to sales and consumption ($0.50/gallon, applied to federal excise tax on sale or use of fuels) and blending ($0.50/gallon for alternative fuel blenders). Other forms of support include government-driven demand: the federal fleet (ie, vehicles used by the federal government) must achieve targets for reduced petroleum consumption, reduced greenhouse gas emissions, and minimum procurement of 'alternative fuel vehicles'. Natural gas vehicles can contribute to meeting these standards.

State and local governments have adopted further incentives. These include vouchers and rebates for the purchase of natural gas vehicles, state-funded grants for fuelling infrastructure, fuel tax exemptions, procurement targets for public sector fleet, and even high-occupancy vehicle lane exemptions for low-emissions vehicles.

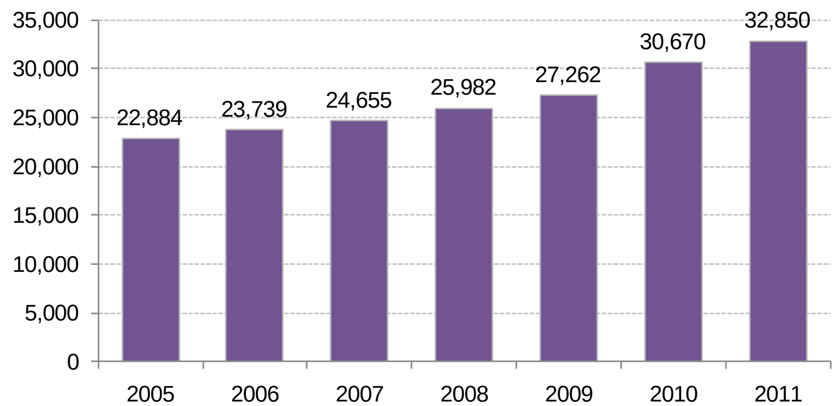
Deployment

Natural gas consumption in the transport sector grew at a rapid compound annual growth rate of 8.5% over 2001-11, though it still accounts for just a sliver of overall gas demand. CNG vehicles have found a niche in the refuse truck and municipal fleet markets, while LNG use for vehicles is still in its very early stages.

In the US, CNG vehicles have gained a foothold in the municipal fleet market and made substantial progress in the refuse truck segment. These vehicles are prolific consumers (refuse trucks consume just under 10,000 gallons of gasoline equivalent per year, against just 531 GGEs for light-duty vehicles), and they return to base daily, which alleviates infrastructure concerns. LNG vehicles make up a much smaller portion of the market.

There are currently around 116,000 CNG- and 3,750 LNG-fuelled vehicles, up from 101,000 and 2,000 in the year 2000, respectively. Total demand as of 2011 was 32,850 million cubic feet (MMcf) (Figure 110).

Figure 110: US natural gas demand from the transport sector, 2005-11 (MMcf)



Source: Bloomberg New Energy Finance, EIA

Table 9: Natural gas fuelling stations

	CNG	LNG
2005	653	30
2006	689	31
2007	726	35
2008	761	37
2009	813	39
2010	873	43
2011	1,000	51
2012*	1,134	60

*Source: Bloomberg New Energy Finance, DOE *As of 30 November 2012*

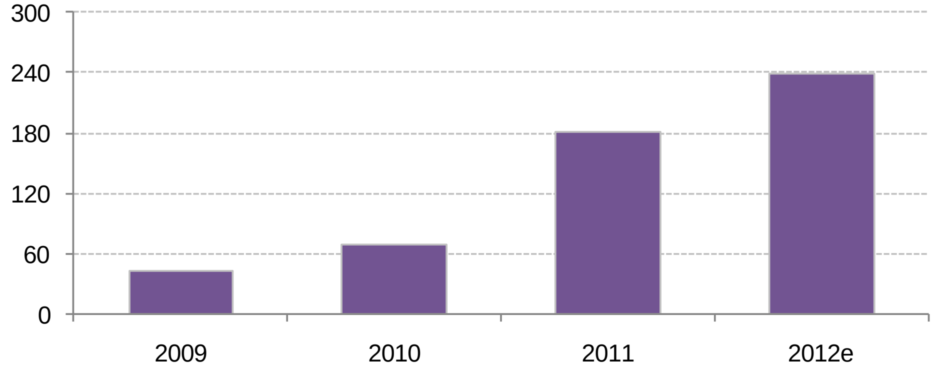
Financing

One measure of financing activity is investment in infrastructure deployment. Indeed, lack of infrastructure is the biggest barrier to substantial further development of natural gas vehicles. There are currently around 1,000 CNG and only 60 LNG fuelling stations in the US, compared to around 119,000 gasoline/diesel stations (Table 9). This presents a classic chicken-and-egg problem: consumers wait for stations to be built, while station builders wait for demand to increase. This barrier is being tackled via a selective build-out of fuelling infrastructure that will open up key corridors.

One company – Clean Energy – is planning to build over 100 new LNG stations by end-2013 in an effort to create 'America's Natural Gas Highway' – a coast-to-coast network of advantageously spaced stations. The business model is to build sufficient fuelling infrastructure within high-use corridors to allow trucking companies to take a regional approach to conversion. (It is worth noting that 85% of US trucking is regional in nature, with fairly fixed routes.) Figure 111 shows the level of 'asset financing' activity, most of which is poured into building fuelling infrastructure, undertaken by Clean Energy.

Figure 111: Measure of asset finance for US natural gas vehicle deployment, 2009-12e

Capex investments by Clean Energy Fuels Corp ($m)



Source: Clean Energy Fuels Corp, annual report 2011 Note: Figures from 2009-11 reflect 'net cash used in investing activities' as per company's cash flow statement; figure for 2012 is based on company plans ("Our business plan calls for approximately $239.5 million in capital expenditures in 2012, primarily related to construction of new fueling stations, America's Natural Gas Highway stations...."

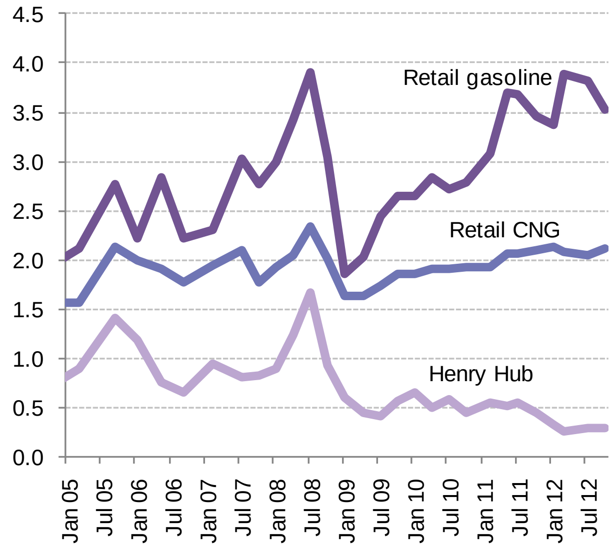
Economics

While natural gas engines function almost identically to gasoline/diesel engines, new fuelling systems are needed. Therefore, a fuel-price discount is needed to incentivize consumers to convert (Figure 112). The economics naturally favour vehicles that consume large amounts of fuel because the costs of conversion are front-loaded and savings accrue on a gallon-by-gallon basis. Thus, natural gas vehicles have already begun to gain a foothold in the heavy-duty (Class 8) truck and fleet vehicle market.

Because of the different characteristics of CNG and LNG, they are best fit for different market segments. The latter's higher energy density but more complicated fuelling logistics make it well-suited for heavy-duty trucks. It is simpler but generally more time-consuming to fuel a CNG vehicle, making it ideal for fixed-route fleet vehicles that return to base daily (ie, refuse trucks, buses).

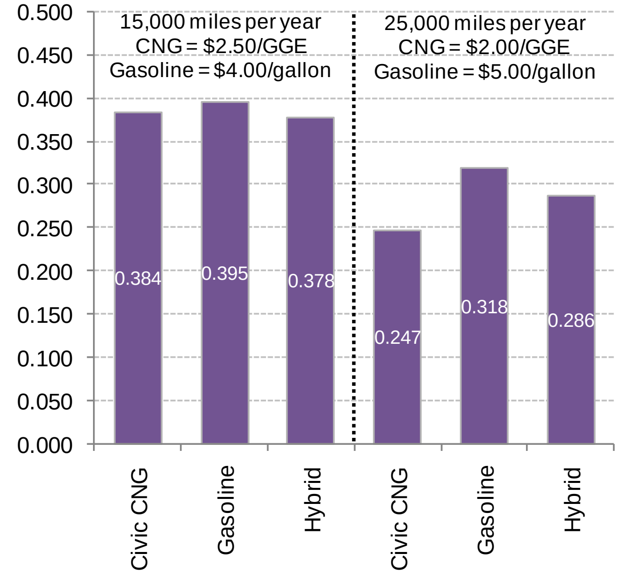
CNG is generally a poor fit in the light-duty market (as a replacement for gasoline, rather than diesel). Because the average American drives fewer than 15,000 miles per year, the fuel savings barely outweigh the additional cost of purchasing a CNG vehicle or paying for a conversion. Materially lower total costs of ownership in the light-duty segment would only be realized at an oil price above $120/bbl and Henry Hub prices below $5.00/MMBtu for drivers that travel more than 20,000 miles per year (Figure 113).

Figure 112: Motor gasoline vs. CNG prices, 2005-12 ($/GGE)



Source: Bloomberg New Energy Finance, DOE

Figure 113: Total cost of ownership: Honda Civic CNG, EX (gasoline), and Hybrid ($/mile)



Source: Bloomberg New Energy Finance, Honda

CNG's target market is much smaller than that of LNG, but station builders and consumers are often the same entity (eg, Waste Management owns and operates both CNG refuse trucks and fuelling stations). Even if they are not, station owners can anticipate volumes with a great deal of confidence. These factors remove much of the project risk that LNG station developers face.

Market dynamics

As noted above, the primary obstacle for the industry concerns insufficient infrastructure – a problem being tackled by Clean Energy.

On the vehicle side, some manufacturers already offer natural gas engines, but most top out at 9 litres (Westport Innovations offers a 15L). Engine manufacturers Cummins Westport, MaxxForce and Volvo are on the verge of offering larger engines designed for regional and long-haul Class 8 over-the-road trucks.

Cummins Westport, a 50:50 joint venture between Westport Innovations and Cummins, will release the 11.9L ISX12-G in 2013; it will be available on Daimler, PACCAR and Volvo trucks. MaxxForce, owned by Navistar, will offer a 12.4L in 2013 on Navistar trucks. In 2014, Volvo plans to begin producing its own 13L LNG engine based on Westport technology. These new engines will complement existing offerings, which include the 8.9L Cummins Westport ISL G, 7.6L MaxxForce ESI, and 15L Westport GX. Because the future of the long-haul market currently rests on the performance of just one engine (the ISX12-G), there is a tremendous amount of adoption risk. The engine is currently being road-tested.

SECTION 8. CROSS-SECTORAL THEMES

This final section sweeps across the preceding analysis to extract recurring and important themes. These include implications for grid reliability, the mixed record of US energy policy, challenges for upstream manufacturing, continued flourishing of innovation, barriers stunting more far-reaching deployment, significance of low-cost financing, and emissions-related benefits of the changes presented throughout the report. Finally, while the shifts in this country's energy sector have been transformative, experiences in other parts of the world demonstrate there is potential for even deeper penetration of sustainable energy technologies.

8.1. Grid reliability

Some changes depicted in this report spell concern for electricity market operators and regulators, for whom reliability is top-of-mind issue. Displacement of coal plants removes gigawatts of reliable baseload capacity from the grid, while a growing role for renewable energy increases the grid's vulnerability to intermittency. At sufficiently high levels of penetration, renewables also create other challenges, such as excess energy (as might occur on windy nights in Texas) and lower wholesale power prices, since these technologies tend to boast very low short-run marginal costs. (Lower wholesale prices damage the economics for other sources of generation. Compensation for the reliability offered by firm sources – eg, via capacity payments – mitigates this effect somewhat.)

But other changes captured here counter these concerns. Smart grid infrastructure increases reliability through enhanced detection and control of the grid; it also enables demand response, which can be quickly dispatched to reduce consumption when generation from renewable resources wanes. Technologies such as pumped storage can ensure grid stability; these resources can be highly responsive to the grid's needs, ramping rapidly to meet a surge in the load, or absorbing excess power (a capability known as decremental reserve). Natural gas plants have long and famously been deployed as 'peakers' and can serve as complements to variable resources.

Threats to reliability may well be met by the promises of increased flexibility.

8.2. Policy record

For nearly all of the sectors analyzed in this report, policy support has been central to advancing deployment. Many of the changes identified – from the impressive growth of small-scale solar to the roll-out of smart grid infrastructure – would undoubtedly have been more muted without policies such as incentives or mandates. Yet the track record of US policy-makers in supporting sustainable energy technologies is mixed.

The wind industry provides a handy case study for evaluating this record. On one hand, the US federal government has supported the industry in the form of a production-based tax incentive, and state governments have promoted the market by implementing RPS, which are often met with wind generation. Yet the tax incentive has been switched on and off repeatedly over the past decade (most recently this year, when the credit actually expired for less than a day before being extended). Moreover, while the state RPS programs created demand towards the end of the last decade, the targets for the upcoming decade will not be high enough to drive significant wind build on their own.

8.3. Upstream manufacturing

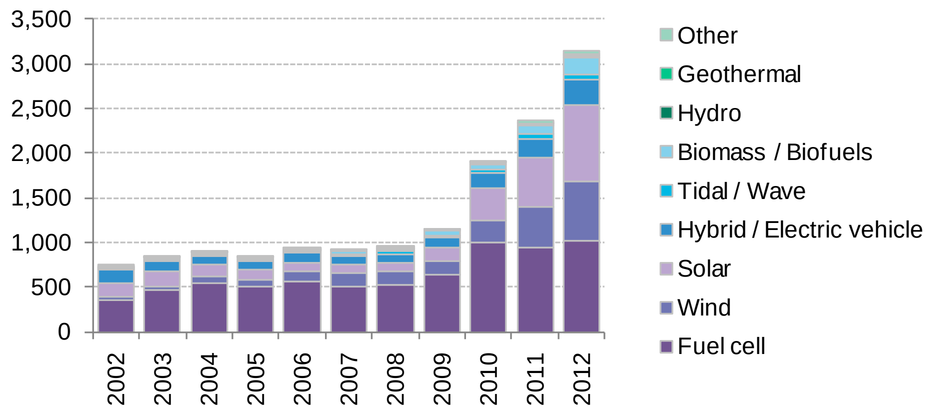
Globally, clean energy manufacturing has suffered in the past year. Bloomberg New Energy Finance's analysis of prices along the PV supply chain – polysilicon, ingots and wafers, cells, modules – shows mostly negative margins for the players offering those components. Some of the most reputable wind turbine manufacturers have seen their margins slip into low single digits and are increasingly turning towards other revenue streams, such as operations and maintenance services. Makers of EV batteries have not seen sales materialize to sufficient levels to absorb capacity.

US companies in these categories have not been spared; indeed, many of them have been among the hardest hit, and the sector has already seen a wave of bankruptcies and consolidations. These troubles are also evidence of competition and maturation, and the pressure on margins has benefited other stakeholders in the industry – namely, downstream players and consumers.

8.4. Innovation

Innovation in the industry, based on measures such as venture dollars (Figure 14) and patent activity, has continued to thrive. Figure 114 below shows the Clean Energy Patent Growth Index, which tracks the number of clean energy patents granted by the US Patent and Trademark Office. The number has ticked up every year since 2007 and reached a record high in 2012.

Figure 114: Clean energy patents granted by the US PTO by technology type, 2002-12Q1 (number of patents)



Source: Clean Energy Patent Growth Index, compiled by Heslin Rothenberg Farley & Mesiti P.C. Note: Some patents are 'double-counted' as they apply to more than one sector.

Patents represent not just entrepreneurial and scientific achievements, but regulatory ones as well, indicating appropriate policy environment and legal structures exist to foster and protect innovation.

8.5. Barriers

The growth of many technologies highlighted in this report could be even more significant save for what are usually a small number of significant barriers. Among the barriers encountered are:

- *Wavering or insufficient policy support*: the on-again/off-again nature of the PTC, for example, has spooked investors and players involved in wind, geothermal, and biomass. The lack of willingness of state regulators to implement time-based pricing has presented a barrier for other sectors.
- *High upfront cost for customers*: some technologies need no subsidies to make their business case against conventional competitors. Yet the business case in support of these sustainable

technologies often rests on total net present value (NPV); the technology is better than the alternative over the lifetime of its use but has a higher upfront cost. Retrofit measures for energy efficiency and advanced vehicles (in some cases) fall into this camp. This is a challenge for these technologies as customers often decide on the basis of head-to-head comparisons of initial costs.

- *Low awareness among potential end-users*: even if the business case works and if the models exist to overcome the upfront costs, potential adopters are often simply not aware that these options exist or are risk-averse. The potential market sizes for distributed generation (eg, fuel cells and CHP) and building efficiency are enormous, but acquisition costs remain high. Energy cost savings may not be top of mind for many potential adopters (eg, building owners and facilities operators).
- *Insufficient enabling infrastructure*: some of the best wind resources in the US remain untapped due to insufficient transmission. Natural gas vehicle growth has been held back by to the chicken-and-egg problem (ie, not enough fuelling stations, but stations will not be built at large scale until natural gas vehicles scale up). Demand response, which FERC cites as necessary to allow significant amounts of renewable resources to be introduced, requires some level of smart meter roll-out and other smart grid technologies.

Some of the most compelling business opportunities in this sector rest with addressing these barriers. Third-party financiers for small-scale solar, for example, tackle the barrier of upfront cost by allowing users to adopt solar under a lease structure; variations on the third-party financing model have existed for years in the energy efficiency world. Some companies have pinned their future success on solving the infrastructure model – ie, by building high-voltage, long-haul transmission lines from the windy corridor running down the middle of the country, or by building natural gas fuelling stations.

8.6. Cost of capital

Equipment costs are important, but the cost of the capital used to finance that equipment matters too. Figure 115 shows how a hypothetical wind project's LCOE rises along with target internal rates of return (IRR). In other words, the cheaper the capital, the more competitive renewable projects are with other forms of generation. (A large utility developing a wind project, for example, might have a low target IRR compared to a private equity investor backing a less proven wind developer.)

Figure 115: Levelized cost of electricity for US wind ($/MWh) by target IRR (%)

Source: Bloomberg New Energy Finance Note: Assumes 100MW project, 30% average capacity factor, 97% technical availability, two-year development period, one-year construction period, and 20-year operational life. Includes PTC and five-year MACRs depreciation. Assumes corporate tax rate of 35%, and 15-year debt at 300 basis points over LIBOR, and inflation rate of 2%.

There has been growing comfort on the part of lenders with sustainable energy technologies, and particularly with renewables such as solar and wind. Meanwhile, even as costs of debt sourced from traditional lenders have decreased, some players in the industry have been dedicated to tapping into even lower costs of capital. Innovation in the financial arena has been a subject of intense interest even among policy-makers.

8.7. Emissions

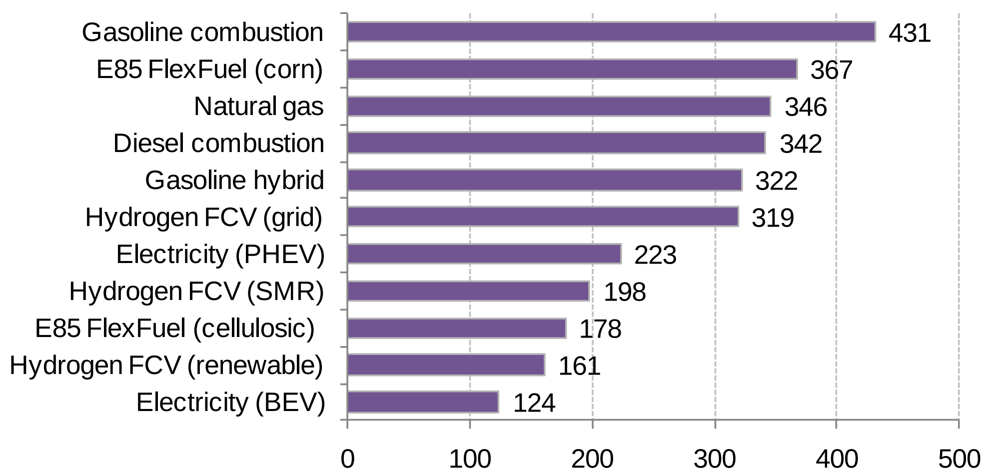
Cleaner, lower-carbon options for energy usage have been a consistent story throughout this report. Figure 116 tells the tale simply as it relates to the transition from a coal-heavy fleet to one drawing increasingly on gas, as it shows how the decrease in coal-related emissions has more than offset the increase in gas-related emissions.

Figure 116: US energy-related CO2 emissions growth (% annual change in CO2 emissions)

Source: Source: Bloomberg New Energy Finance, EIA

Similarly, as with the power sector, advanced transportation technologies emit significantly fewer greenhouse gases on a well-to-wheel basis (including fuel production, distribution and vehicle emissions) (Figure 117).

Figure 117: Well-to-wheels emission comparison by fuel type (grams of GHG/mile)

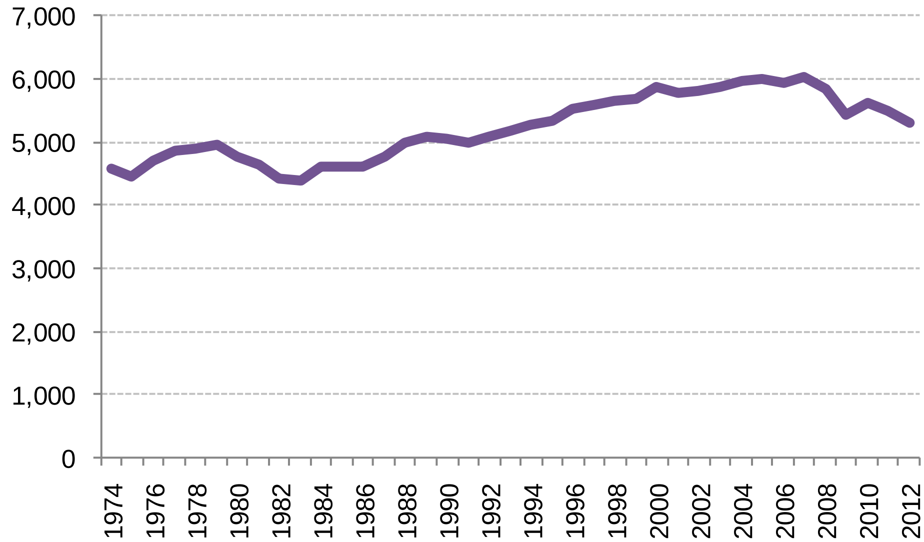


Source: Bloomberg New Energy Finance, California Energy Commission, California Fuel Cell Partnership
Note: Total emissions are calculated as greenhouse gases emitted due to fuel production and distribution,

and vehicle emissions. Emissions are normalized to use a 2012 model year four-passenger sedan. California Energy Commission assumes that 'renewable-powered- fuel cell vehicles are powered by 70% renewable. FCV is fuel cell vehicle, SMR is steam methane reforming, PHEV is plug-in electric, BEV is battery electric.

Emissions-related benefits are a common thread running across all of the 'sustainable energy' technologies. Together, the profound changes wrought by these technologies have resulted in an about-face for the country's emissions trajectory: energy-related CO_2 emissions climbed almost every year between 1990 and 2007, peaking at 6.02Gt that year. They have since fallen by 12% and in 2012 were at their lowest since 1994.

Figure 118: US energy-related CO_2 emissions, 1974-2012 (MtCO2e)



Source: EIA

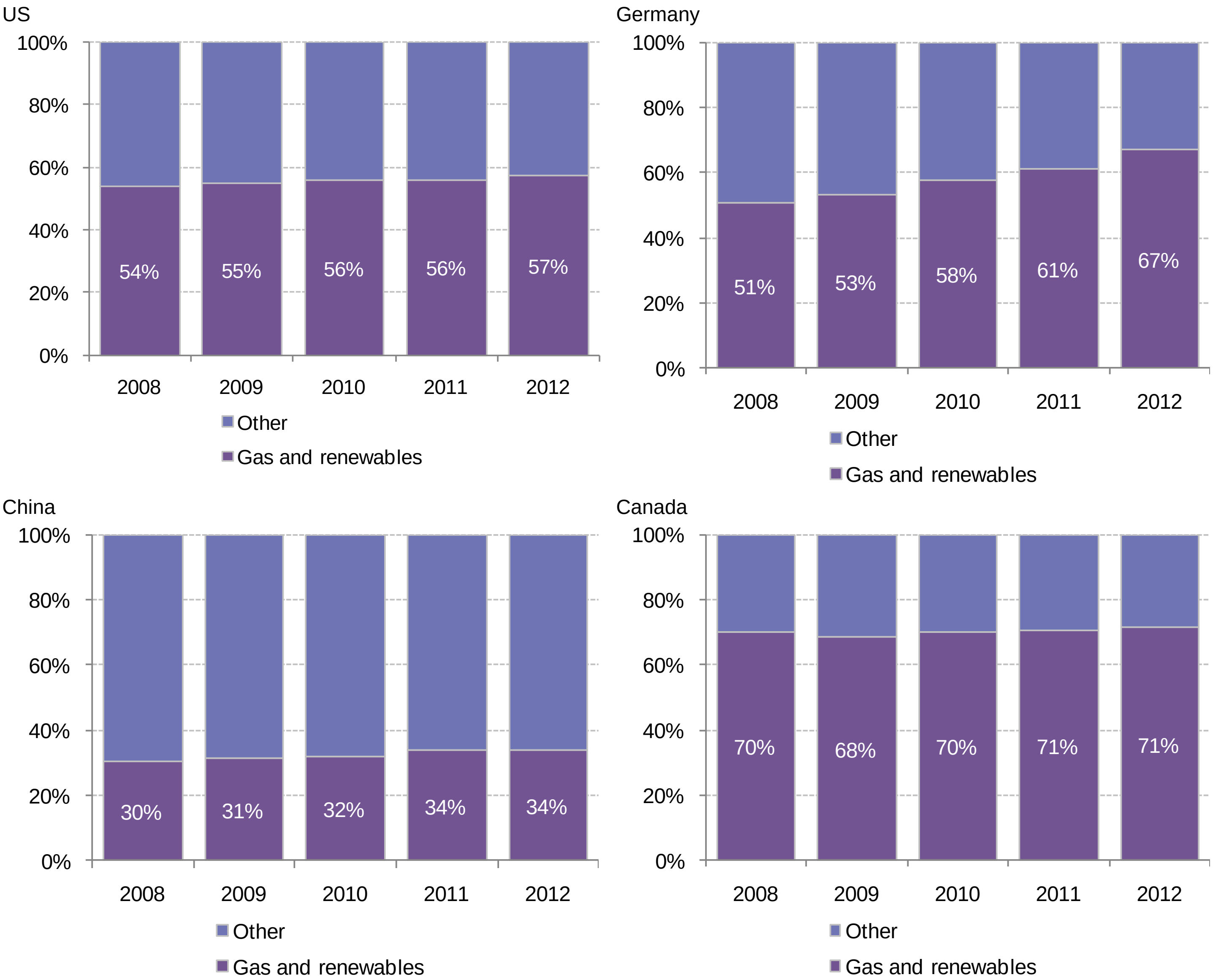
8.8. Cross-country comparison

Figure 119 below shows the role that gas and renewables are combining to play in US power compared to other countries.

If renewable energy has climbed markedly as a percentage of capacity and generation in the US, it has veritably exploded in Germany where it today accounts for 48% of capacity. At times, solar-generated electricity alone represents over half of Germany's total generation. In Canada, hydropower is dominant, accounting for 55% of capacity. No other country, however, has seen such a dramatic emergence of gas as the US. (This cross-country analysis does not cover the roles of sectors such as CHP, efficiency, and advanced transport.)

The underlying story behind this report has been that the US energy sector is in the midst of a transformation. The experiences in other parts of the world demonstrate there is potential for even deeper penetration of sustainable energy technologies.

Figure 119: Comparison of contributions from gas and renewables to nameplate capacity across select countries, 2008-12



Source: Bloomberg New Energy Finance

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