

FEBRUARY 2014

2014

Sustainable Energy in America

FACTBOOK

Bloomberg
NEW ENERGY FINANCE

The Business Council for
 **Sustainable
Energy**[®]

No portion of this document may be reproduced, scanned into an electronic system, distributed, publicly displayed or used as the basis of derivative works without attributing Bloomberg Finance L.P. and the Business Council for Sustainable Energy. For more information on terms of use, please contact sales.bnef@bloomberg.net. Copyright and Disclaimer notice on the last page applies throughout. Developed in partnership with the Business Council for Sustainable Energy.

CONTENTS

EXECUTIVE SUMMARY	_____	1
SECTION 1.	INTRODUCTION _____	7
SECTION 2.	A LOOK ACROSS THE US ENERGY SECTOR _____	9
2.1.	US energy sector: a bird's-eye view.....	9
2.2.	Policy.....	12
2.3.	Finance	13
2.4.	Economics.....	16
SECTION 3.	NATURAL GAS _____	18
3.1.	Policy.....	18
3.2.	Development	20
3.3.	Financing.....	24
3.4.	Economics.....	25
3.5.	Market dynamics	28
SECTION 4.	LARGE-SCALE RENEWABLE ELECTRICITY _____	29
4.1.	Policy for all renewables	29
4.2.	Large-scale solar (PV, CSP).....	31
4.3.	Wind	36
4.4.	Biomass, biogas, and waste-to-energy	41
4.5.	Geothermal.....	47
4.6.	Hydropower	50
SECTION 5.	DISTRIBUTED POWER, STORAGE, CCS _____	53
5.1.	Small-scale solar	53
5.2.	Small- and medium-scale wind	56
5.3.	Small-scale biogas	59
5.4.	Combined heat and power and waste-heat-to-power.....	60
5.5.	Fuel cells (stationary)	65
5.6.	Energy storage	69

5.7.	Carbon capture and storage	75
SECTION 6.	DEMAND-SIDE ENERGY EFFICIENCY _____	80
6.1.	Energy efficiency	80
6.2.	Smart grid and demand response.....	96
SECTION 7.	SUSTAINABLE TRANSPORTATION _____	102
7.1.	Electric vehicles.....	102
7.2.	Natural gas vehicles	109
SECTION 8.	CROSS-SECTORAL THEMES _____	114
8.1.	Climate: a new federal policy focal point.....	114
8.2.	CO2 emissions: declining long-term despite a 2013 uptick	115
8.3.	Grid reliability and system resilience: more important than ever	116
8.4.	Distributed generation: transformative potential and a threat to business-as-usual.....	117
8.5.	Cost of capital: critical to cutting sustainable energy costs.....	117
8.6.	Barriers: remaining impediments to sustainable energy deployment	118
8.7.	Regional comparisons: leading and lagging states	119
8.8.	Cross-country comparisons: the US in context	120
8.9.	The energy independence dream: getting closer	121
ABOUT US	_____	123

TABLE OF FIGURES

Figure 1: Understanding terminology for this report.....	8
Figure 2: US primary energy consumption vs GDP, 1990-2013	9
Figure 3: US electricity demand, 1990-2013	9
Figure 4: US electricity generation by fuel type, 2007-13 (%).....	10
Figure 5: US electricity generation by fuel type, 2007-13 (TWh).....	10
Figure 6: US capacity build by fuel type, 1990-2012 (GW)	11
Figure 7: US renewable capacity build by technology, 2008-13 (GW)	11
Figure 8: US cumulative renewable capacity by technology (including hydropower), 2008-13 (GW).....	12

Figure 9: US cumulative non-hydropower renewable capacity by technology, 2008-13 (GW).....	12
Figure 10: US renewable generation by technology (including hydropower), 2008-13 (TWh)	12
Figure 11: US non-hydropower renewable generation by technology, 2008-13 (TWh).....	12
Figure 12: Total new US investment in clean energy, 2004-13 (\$bn)	14
Figure 13: US asset (large-scale project) finance investment in clean energy by sector, 2004-13 (\$bn).....	14
Figure 14: US VC/PE investment in clean energy by sector, 2004-13 (\$bn).....	15
Figure 15: US public market investment in clean energy by sector, 2004-13 (\$bn)	15
Figure 16: Returns of clean energy indexes relative to benchmark indexes (%).....	15
Figure 17: Clean energy investment types and flows in the US, 2013 (\$bn) (as per Bloomberg New Energy Finance definition of clean energy).....	16
Figure 18: Levelized cost of electricity across power generation technologies, Q4 2013 (\$/MWh)	17
Figure 19: US coal power plant retirements completed and announced, 2011-2013	20
Figure 20: US dry natural gas production and gas-directed rig count, 2006-2013	21
Figure 21: Gas production per rig (mcf).....	21
Figure 22: Gas production in the continental US (Bcfd).....	21
Figure 23: Existing natural gas distribution pipeline, 1990-2012 (million miles)	22
Figure 24: Natural gas distribution mainline material, 1990-2012 (million miles).....	22
Figure 25: US natural gas transmission pipeline capacity additions,1996-2012 (Bcfd)	22
Figure 26: US natural gas demand by end-use, 2008-13 (Bcfd).....	23
Figure 27: US natural gas residential customers vs. residential consumption	23
Figure 28: Industrial electricity production from on-site generation by source, 2008-12 (TWh)	24
Figure 29: Organic exploration and development spending by independent exploration and production companies, 2008-12 (\$bn)	25
Figure 30: US midstream gas construction expenditures, 2008-12 (\$bn)	25
Figure 31: Cost of supply evolution for two plays within the Haynesville and Marcellus , 2011-14 (\$/MMBtu).....	26
Figure 32: Cost of generating electricity in the US from natural gas vs. coal, trailing two years (\$/MWh).....	27

Figure 33: LCOE comparison for natural gas vs. coal (\$/MWh).....	27
Figure 34: Methanol cash margins by main feedstock (\$/t)	27
Figure 35: LNG cost build, US Gulf Coast to Europe (\$/MMBtu)	27
Figure 36: Global PV module production by country, 2008-12 (GW)	32
Figure 37: Global PV demand by country, 2008-13 (GW)	32
Figure 38: US utility-scale photovoltaic build, 2008-13	33
Figure 39: US concentrating solar power build, 1984–2013	33
Figure 40: Venture capital/private equity investment in US solar by type, 2008-13 (\$bn)	33
Figure 41: Asset finance for US utility-scale solar projects by type, 2008-13 (\$bn).....	33
Figure 42: Capex – price of c-Si PV modules, 1976–2012 (\$/W).....	34
Figure 43: Capex – best-in-class cost of global utility-scale PV, 2010-13 (\$/W)	35
Figure 44: Solar REC prices in selected states’ markets, 2013 (\$/MWh).....	35
Figure 45: US wind build, 2004-13	37
Figure 46: Wind turbine production capacity in the US by manufacturer, 2008-13 (GW)	37
Figure 47: Wind turbine supply contracts for commissioned US projects by commissioning year, by manufacturer, 2008-13 (GW)	37
Figure 48: Asset finance for US wind projects, 2004-13 (\$bn).....	38
Figure 49: Capex – wind turbine price index by turbine type and delivery date, 2008-14 (\$m/MW)	38
Figure 50: PPA prices for select US wind markets (\$/MWh).....	39
Figure 51: ‘Class I’ REC prices in selected markets, 2013 (\$/MWh).....	40
Figure 52: Top 10 US wind owners, as of end-2013 (MW)	40
Figure 53: US wind capacity commissioned or under construction by type of developer, 2006-13 (MW)	40
Figure 54: US biomass-to-power build, 2008–13.....	43
Figure 55: US biogas and waste-to-energy build, 2008–13	43
Figure 56: Asset finance for US biomass, 2004-13 (\$m)	44
Figure 57: Asset finance for US biogas and waste-to-energy, 2004-13 (\$m).....	44
Figure 58: Biomass feedstock prices in selected US markets, 2011–13 (\$/dry tonne).....	45
Figure 59: Capex – capital costs for biogas and waste-to-energy projects by type, 2007-12 (\$m/MW).....	45

Figure 60: US geothermal project build, 2008-13	47
Figure 61: Asset finance for US geothermal projects, 2008-13 (\$m)	48
Figure 62: Capex – capital costs for geothermal projects by type, 2008-13 (\$m/MW)	49
Figure 63: US hydropower project build, 2009-13	51
Figure 64: US new hydropower capacity licensed or exempted by FERC, 2009-13 (MW)	51
Figure 65: Annual asset finance for US hydropower projects, 2008-11 (\$m)	51
Figure 66: US small-scale PV build by type, 2008-12	54
Figure 67: US small-scale solar project financing by type, 2008-12 (\$bn)	54
Figure 68: Cumulative funds closed by selected third-party financiers, 2008–13 (\$m).....	55
Figure 69: Capex – best-in-class cost of global commercial-scale PV, 2010-12 (\$/W)	56
Figure 70: Capex – best-in-class cost of global residential PV, 2010-12 (\$/W).....	56
Figure 71: US small-scale wind build, 2002-12	57
Figure 72: US medium-scale wind build, 2002-12	57
Figure 73: Average small wind turbine (<100kW) price and average turbine size.....	58
Figure 74: US anaerobic digester projects, 2008-11	59
Figure 75: US CHP build, 2008-12	61
Figure 76: US CHP generation from plants tracked by EIA generation data, 2008-13 (TWh)	61
Figure 77: US CHP deployment by sector	62
Figure 78: US CHP deployments by fuel source	62
Figure 79: Asset finance for US CHP projects, 2006-10 (\$bn).....	63
Figure 80: Capex – capital costs for CHP installations (\$m/MW).....	64
Figure 81: US stationary fuel cell capacity, installed and planned, by technology, 2007- 13 (MW)	66
Figure 82: US stationary fuel cell capacity, installed and planned, by size of installation, 2007-13 (MW)	66
Figure 83: California stationary fuel cells annual capacity installed, 2007-13, by major supplier (MW)	67
Figure 84: Stationary fuel cell capacity in top 10 US states, 2007-present, planned and installed (MW)	67
Figure 85: Venture capital / private equity investment in US fuel cell companies, 2008-	

13 (\$m).....	68
Figure 86: Average PJM regulation prices before and after FERC 755 implementation (\$/MWh)	69
Figure 87: Average MISO regulation prices before and after FERC 755 implementation (\$/MWh)	69
Figure 88: Cumulative energy storage capacity, 2000-12 (GW)	71
Figure 89: Announced non-hydropower energy storage projects in the US (MW and number of projects).....	72
Figure 90: Commissioned non-hydropower energy storage projects in the US (MW and number of projects).....	72
Figure 91: Capital costs of select storage technologies – technology developer estimates (\$/kWh).....	73
Figure 92: Capital costs of select energy storage technologies – actual project data (\$/kWh).....	73
Figure 93: Non-hydropower announced energy storage projects in the US by technology (% by MW).....	74
Figure 94: Non-hydropower applications for announced energy storage technologies in the US (% by MW).....	75
Figure 95: Total CO2 injection rate by current status of US CCS projects (MtCO2/yr).....	76
Figure 96: Asset finance for post-financial investment decision US CCS projects, 2007-12 (\$m).....	78
Figure 97: Estimated first-of-a-kind (FOAK) capital cost for CCS projects (\$m/MW)	79
Figure 98: US states by type of electricity policy for decoupling, 2000-13 (number of states)	81
Figure 99: US states by type of natural gas policy for decoupling, 2000-13 (number of states)	81
Figure 100: US states adopting EERS, 2000-13 (number of states).....	81
Figure 101: Utility energy efficiency spending and budgets, 2006-12 (\$bn).....	81
Figure 102: Share of total electricity consumption by US state, by region, 2012.....	82
Figure 103: Availability of PACE financing by US sector and state, as of July 2013	83
Figure 104: Propagation of PACE programs in California cities and counties, 2010- July 2013 (by population size).....	83
Figure 105: US building floor space covered under state or local building benchmarking / disclosure policies, 2007-13.....	84

Figure 106: Stringency of ASHRAE Standard 90 in terms of chiller performance, 1977-2016 (coefficient of performance)	85
Figure 107: Thermal performance standards by building placement for residential buildings (R-values).....	85
Figure 108: Thermal performance standards by building placement for commercial buildings (R-values).....	85
Figure 109: ACEEE state-by-state scorecard for energy efficiency policies, 2013.....	87
Figure 110: Number of federal ESPCs executed through the DOE's umbrella agreement, 1998-2013	88
Figure 111: Contract value of federal ESPCs executed through the DOE's umbrella agreement, 1998-2013 (\$m)	88
Figure 112: US commercial building energy intensity, 1980-2012 (kBtu/ft ²).....	89
Figure 113: Energy Star-certified floor space in US non-residential buildings, categorized by usage, 1999-2013 (bn ft ² of floor space)	90
Figure 114: Energy Star-certified floor space and total floors space for US commercial buildings, segmented by sector and building size, December 2013	90
Figure 115: US manufacturing consumption of energy as a fuel, 2002-10 (trillion Btu).....	91
Figure 116: US production of primary vs secondary aluminum, 1980-2012p.....	92
Figure 117: US aluminum cans collected for recycling and % of total cans collected	92
Figure 118: Investment in energy efficiency through ESCOs and utility programs, categorized by program, 1993-2012 (\$bn)	93
Figure 119: Investment in energy efficiency through ESCOs and utility programs, characterized by end-user, 1993-2012 (\$bn)	93
Figure 120: Funded improvements and funds available, Sonoma County Energy Independence Program	94
Figure 121: Number of federal ESPCs executed through the DOE's umbrella agreement, sorted by LCOE savings and deal size, 1998-2013.....	95
Figure 122: Total value of federal ESPCs executed through the DOE's umbrella agreement, sorted by LCOE savings and deal size, 1998-2013 (\$m)	95
Figure 123: US electric smart meter deployments, 2008-13 (m units)	98
Figure 124: US electric smart meter penetration (smart meter deployment as percent of total US electricity customers)	98
Figure 125: Incentive-based demand response capacity by US ISO/RTO, 2008/09-2013/14 (GW).....	98

Figure 126: US smart grid spending by segment, 2008-13 (\$bn)	99
Figure 127: US gasoline consumption, 1984-2013 (bn gallons)	102
Figure 128: Fuel economy standards for US light-duty vehicles relative to other countries, 2002–25e (mpg).....	103
Figure 129: US passenger hybrid, plug-in hybrid and battery electric vehicle sales, 2012-13 (thousand units).....	105
Figure 130: Hybrid, plug-in hybrid and battery electric vehicles as percentage of total US passenger vehicle sales, 2012-13 (%)	106
Figure 131: Venture capital / private equity funds raised by US EV firms(\$m).....	106
Figure 132: Total cost of ownership of select vehicles in the US (\$).....	107
Figure 133: US natural gas demand from natural gas vehicles, 2005-13 (Bcf).....	110
Figure 134: Capex investments by Clean Energy Fuels, mostly for new natural gas fueling stations, \$m 2009-13e.....	111
Figure 135: CNG prices compared with gasoline and Henry Hub natural gas prices, 2006-13 (\$/GGE).....	112
Figure 136: US GHG emissions, energy sector and economy-wide (MtCO ₂ e).....	115
Figure 137: Project bonds and publicly-traded clean energy investment vehicles in North America and the UK, 2013 (dividend yield %, transaction date, size) ...	118
Figure 138: US dry natural gas proved reserves by state, 2011 (Tcf).....	119
Figure 139: Investments in renewable energy by state, 2006-13 (\$bn)	120
Figure 140: Contributions from natural gas and renewables as a share of national total nameplate capacity, 2008-12 (%)	121
Figure 141: GDP per unit of electricity generated, 1985-2012 (GDP on purchasing power parity basis, in \$bn, per TWh)	121
Figure 142: US primary energy consumption, production, and net imports, 1981-2013 (quadrillion Btu)	122
Figure 143: US crude oil production and imports, 1975-2013 (million barrels per month)	122

TABLE OF TABLES

Table 1: Tax incentives for US sustainable energy.....	30
Table 2: Supply-demand balance of selected 'Class I' RPS programs, grouped by region	31

Table 3: Comparison of fuel cell types	66
Table 4: California energy storage incentives and subsidies	70
Table 5: Basic assumptions for total cost of ownership analysis	107
Table 6: Electric vehicle plans, partnerships, and supply chain relationships for major auto companies	108
Table 7: Fuel cell vehicle plans of major auto companies.....	108
Table 8: Natural gas fueling stations	111
Table 9: List of light-duty CNG vehicles available in 2014	112
Table 10: Number of models available for CNG heavy- and medium-duty vehicle platforms	113

EXECUTIVE SUMMARY

A revolution is transforming how the US produces, delivers, and consumes energy. The mix of supply is changing rapidly, with low-carbon sources gaining share, while consumption is declining, despite overall economic growth.

The Sustainable Energy in America Factbook provides a detailed look at the state of US energy and the role that a range of new technologies are playing in reshaping the industry. First published in January 2013, the Factbook is researched and produced by Bloomberg New Energy Finance and commissioned by the Business Council for Sustainable Energy. This represents the second edition of the Factbook.

In some cases, developments in 2013 cemented trends depicted in the first report. New technologies – such as techniques for extracting natural gas from shale and vehicles fueled by electricity – continue to gain traction. New investment dollars continue to find opportunities – such as residential solar installations on residences and commercial building energy efficiency improvements – that profitably enable this transformation. For some sectors, such as distributed generation and storage, policy continues evolving to accommodate changing conditions or accelerate these changes.

In other cases, 2013 marked a departure. Total energy consumed (up relative to 2012), the amount of emissions associated with that energy consumption (up), the portion of electricity generation from coal (up), and the amount of new investment into renewable energy (down) all bucked longer-term trends. The Factbook explains these changes and highlights why some likely are temporary deviations while others could represent a new trajectory for at least the next several years.

The goal of the Factbook remains the same: to offer simple, accurate benchmarks on the status and contributions of new sustainable energy technologies.

What's unique about this Factbook

- The report is **quantitative and objective**, intended to arm policy-makers, journalists, and industry professionals with up-to-date, accurate market intelligence.
- It examines **'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, distributed power, and energy efficiency.
- It **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.

Key findings

The long-term transformation of how the US produces and consumes energy continues...

- The country's total annual energy consumption in 2013 was 5.0% below 2007 levels, thanks to advances in energy efficiency. This long-term trend was in part prompted by the economic downturn of 2008-09, but as economic growth has returned energy use has not grown at a commensurate rate. The net result is a far more energy-efficient economy.
- Over that same period (2007-13), use of lower- and zero-carbon energy sources has grown, while other major energy sources such as coal and oil have experienced significant declines. Natural gas production and consumption hit all-time highs in 2013, and natural gas-fired power plants provided 28% of US electricity in 2013, up from just 22% in 2007. Renewable electricity generation, including power from large hydro projects, grew from 8.3% to 12.9% over that period. Since 1997, 94% of new power capacity built in the US has come in the form of natural gas plants or renewable energy facilities.
- Transportation is being revolutionized by new policies, technologies, and fuels. Federal corporate average fuel economy (CAFE) standards for cars are set to double by 2025, relative to 2011 levels. Sales of hybrids and plug-in electric vehicles are rising and totalled nearly 600,000 vehicles in 2013 (3.8% of US passenger vehicle sales). Natural gas use in the transport sector is up 33% since 2007. These developments, along with a growing role for biofuels, have driven gasoline consumption down 7.7% since 2005.
- These trends have combined to put US CO₂ emissions on a long-term downward trajectory. In 2009, President Obama announced a goal of achieving a 17% reduction in greenhouse gas (GHG) emissions by 2020 relative to 2005 levels. With total GHG emissions having peaked in 2007 at 7.26Gt and having dropped by an estimated 9.8% since 2005, the US is now more than halfway to its goal.

...but there were some noteworthy detours in 2013...

- Energy consumption inched up by 1.4% in 2013 after having declined by 6.3% over the 2007-12 period – but nevertheless likely grew at a slower rate than GDP.
- Total new renewable energy capacity additions stalled with an estimated 5.4GW installed in 2013 compared with 18GW in 2012. New investment of \$48.4bn was well off the all-time high of \$68.5bn in 2011. Still, a record volume of solar photovoltaic (PV) capacity was added in 2013, including 2GW of utility-scale solar and an equal amount of small-scale installations, and 2014 is forecast to be a stronger year for the two largest renewable energy sub-sectors, solar and wind.
- Natural gas's contribution to the US electricity mix dropped in 2013 from 2012 levels and coal generation rebounded slightly. Natural gas prices rose from historic lows seen in 2012, allowing coal to be somewhat more cost-competitive. Natural gas accounted for 28% of 2013 electricity generation, down from 31% in 2012. Other natural gas-consuming sectors, though, all saw increased use in 2013, resulting in 2013 natural gas consumption topping 2012 levels.

...and some major new developments sure to impact sustainable energy growth going forward.

- *The Obama administration demonstrated renewed commitment to addressing climate change.* In his first term, the President ardently supported research, development, and deployment of low-carbon energy technologies, but rarely cited climate as the rationale behind his policy decisions. In June 2013, he announced his intention to address GHG emissions domestically and internationally – with or without Congressional support. Standards for new-build coal plants as drafted by the Environmental Protection Agency would effectively bar new coal without carbon capture and storage (CCS) technology. Standards for existing coal plants, due in mid-2014, could require facilities to install expensive technologies to reduce ‘criteria pollutants’ (eg, sulfur dioxide, nitrogen oxides and mercury). Though they face legal challenges and hang regulatory uncertainty over the US electricity sector, the proposed policies are already playing a role in the transformation underway: more than 40GW of coal plants have either already been retired or announced plans to do so since 2011 (due to the policies, as well as old age and thinning margins).
- *Natural gas continued its remarkable boom.* The emergence of new technologies has enabled the commercially viable extraction of unconventional natural gas resources including shale – a domestic, abundant, fuel. Production continues to be strong, although the rate of growth of production has slowed compared with recent years as prices have softened and as producers have increased focus on oil- and liquid-rich plays. Investments by the upstream portion of the industry – exploration and production – have been on a steep upward trend; and investments in the midstream portion – including storage capacity and pipelines that connect supply basins and storage to centers of demand – totalled \$15bn in 2012.
- *Demand for gas reached an all-time high in 2013 and is on pace to rise further in 2014.* Natural gas demand grew by more than 3Bcfd in 2011-12, and grew yet again by 0.8Bcfd in 2013. Low prices have made it the fuel of choice for new power plant build, spurred fuel-switching for homes and businesses, and captured the attention of fuel-hungry transport industries. It has led companies to seek permission to export liquefied natural gas (LNG) and piqued the interests of energy-intensive industrial consumers. Since 2010, there have been 10 restarts or expansions of industrial plants in the US across the gas-intensive ammonia, methanol, and ethylene sectors, including six in 2013, and there are many new-build industrial plants planned for 2015 and beyond.
- *Renewable electricity generation costs touched all-time lows allowing renewable in some locations to underprice fossil-fueled competitors.* Prices of solar modules have declined by 99% since 1976 and by about 80% since 2008. Total system costs for global, best-in-class utility-scale solar installations are now \$1.55/W and expected to continue falling. As a result, power-purchase agreements (PPAs) for projects that are expected to be completed around 2016 have featured prices below \$70/MWh. The results for wind have been even more startling; utilities in Texas, the Southwest, and the Midwest signed PPAs in the \$20-35/MWh range for wind projects that are coming online in the 2014-15 period; these prices are well below the levelized cost of electricity of thermal technologies (eg, low \$60s for natural gas). The benefits of these economics, which are made possible with the support of tax credits, can flow to the consumer; a Michigan utility recently announced that it is lowering customers’ electricity rates by 6.5% in 2014, citing low-cost wind as one of the major factors.

- *US renewable energy investment showed it remains highly responsive to policy.* Record-high investment in 2011 in renewable and energy efficiency-related technologies was an outcome of the 2009 federal stimulus package, but those programs are mostly finished. Investment in 2013 was hit hard by uncertainty that lingered throughout 2012 over the fate of an important incentive for renewables, the Production Tax Credit (PTC). Though the PTC was renewed at the beginning of 2013, it has taken a while for project developers to reconstitute their pipelines and refresh the wave of financing activity. Furthermore, since different technologies have different lead times, some sectors see quicker responses to policy changes in terms of financing and deployment levels. A bright spot for renewable energy investment was PV, which enjoys longer-term policy certainty; its chief federal incentive, the Investment Tax Credit, is on the books through 2016. In terms of actual legislative activity in 2013, most efforts stalled, with the exception of two bills focused on streamlining hydropower projects.
- *Energy efficiency policy is maturing, and investments are ramping up, to the benefit of buildings and industries.* As of 2013, 26 states had energy efficiency resource standards (EERS); 31 states, covering 77% of the US population, had legislation enabling energy efficiency deployment to be paid through property tax bills, or PACE (although PACE financing is not yet available in most of these states); and 7% of US commercial sector floor space was covered under policies requiring buildings to achieve energy efficiency benchmarks or mandating disclosure of energy consumption. Energy efficiency financing (not captured in Bloomberg New Energy Finance's numbers) across two major frameworks – utility spending to comply with resource standards and energy service companies' (ESCOs) investments – has been on an upward trend and amounted to more than \$12bn in 2012. Energy intensity in key industrial sectors has been falling; while manufacturing industrial output decreased by 3% over 2002-10, energy consumption fell by 17%. For buildings, meanwhile, electricity intensity has increased, likely owing to an increase in the number of electricity-consuming appliances within modern buildings. Yet the rate of Energy Star certification has accelerated since the mid-2000s to the point that over 3bn square feet of floor space is now covered.
- *Distributed generation emerged as a transformative phenomenon – if not yet in substance, then as a foreshadower of what's to come.* Most of the country's electricity continues to come from large-scale, centralized power plants. Distributed generation sources have a relatively modest presence by comparison; small-scale PV, for example, accounts for less than 1% of electricity sales in all states save for Hawaii. But the total addressable market is gigantic, and the category is attracting investors; from 2008 to 2013, third-party solar financiers raised \$6.7bn to install systems. The rise of distributed generation is ushering into the US power industry new players and new business models, and testing the durability of old ones. The stakes are high, as evidenced by the intense regulatory battles that played out across the country in 2013 over the relative costs and benefits of distributed PV. Other distributed technologies are also seeing momentum. Combined heat and power, which makes up 8% of US electric generating capacity, saw 870MW installed in 2012 and potentially more in 2013. Increased attention to energy resilience, along with improved economics and favorable policy, have led to a growing interest in microgrids – small versions of power systems that can combine various technologies, such as distributed solar, storage, CHP, diesel back-up, fuel cells, and smart grid systems – to meet a local electric load.
- *The need for flexibility in how electricity distribution is managed to ensure grid reliability is becoming more apparent.* 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, variable renewables). Yet other changes afoot – including reduced electricity demand through energy efficiency and a growing role for dispatchable resources such as natural gas plants, hydropower, and demand response (now a 28GW-sized market) – can help the electricity industry meet this challenge. Policy may need to adjust, however, as most market structures do not yet fully recognize the benefits of some of the technologies offering increased flexibility, such as energy storage.

- *The age of intelligent homes and a more intelligent grid is on the horizon.* Some 53m smart meters have been deployed in the US, though the pace of deployment is slowing as stimulus spending is largely exhausted, and untapped market potential is shrinking. Other investment areas in the smart grid industry include distribution automation, home area networks, and smart grid analytics software. Investments in distribution automation focus on management of grid assets, improved grid optimization, and fault location, isolation, and restoration. Home area network deployments include in-home displays, smart thermostats, smart appliances and other load control devices. Smart grid data analytics offer utilities the ability to achieve improved customer segmentation, better theft detection and improved program targeting. The smart grid industry also plays a role in infrastructure resilience; smart grid technologies can help a utility more quickly and accurately identify areas with outages or other service issues during and after storms, facilitating the recovery process and allowing utilities to prioritize critical areas.
- *Other advanced energy technologies have made important progress.* Biogas, already used selectively in the power sector, could also have a role to play in transport. Stationary fuel cells (144MW of cumulative capacity) while representing very much a nascent technology, had their strongest year ever for deployment in 2013, thanks in part to grants, credits, or other incentives offered by states. Non-hydropower storage technologies (409MW cumulative) – including batteries, flywheels, and compressed air – are more expensive than pumped hydropower. But their costs have declined markedly in the recent years, and, in specific regions, their business case has been strengthened by state procurement mandates and by policies that call for compensation for frequency regulation. In the case of CCS (12 projects operational), the largest, most advanced project in the US, Mississippi Power Kemper (582MW net), has had a difficult journey but is now approaching completion.

This long-term transformation has major implications for the US economy, US energy security, and global concerns over climate change

- *Total US emissions peaked in 2007 and have fallen 9.8% since 2005.* Even without a legislated federal carbon reduction policy, the US is more than halfway to its goal of a 17% reduction on emissions by 2020, relative to 2005 levels, due in large part to the contributions of natural gas, renewable energy, and energy efficiency. While 2013 emissions actually ticked up, they are expected to continue to drop over the medium to long term as more coal capacity comes offline and is replaced by lower-carbon alternatives. Whether the 17% cut can be achieved remains an open question.
- *Participation in this transformation is far from evenly distributed across the country.* Texas and Louisiana are among the states that sit on the richest reserves of shale gas while the Marcellus shale in the Northeast has singlehandedly more than offset declines in dry gas production from elsewhere in the US. From 2006 to 2013, over half of all US renewable energy investment occurred in just six states: California, Texas, Iowa, Illinois, Arizona, and Oregon. Installation of

renewable energy projects has favored regions with excellent resources, attractive policies, high electricity prices, or, as in the case of California, all three. A scorecard that measures energy efficiency policies across the 50 states shows that states in the Northeast and along the Pacific coast lead the way in terms of strength of policy positions.

- *Seemingly overnight, the transformation has awakened the prospect of greater energy security, as the US has become more self-reliant.* Net energy imports are estimated to have fallen by 15% between 2012 and 2013 and by more than 50% since 2005. October 2013 marked the first month since early 1995 that US crude oil production surpassed imports. Since 2003, US natural gas pipeline exports to Mexico have doubled, and to Canada have more than tripled. This trend at least directionally toward some form of greater energy independence has substantial implications for economic competitiveness and for geopolitics. Policies, infrastructure, and strategies that were designed before this trend took shape may need to be re-examined and perhaps overhauled.
- *Investors in publicly-traded companies that are a part of this transformation saw share prices appreciate in 2013.* After five years of dismal returns for clean energy stocks, shares for many publicly traded clean energy companies surged in 2013, a reflection of greater investor confidence both in the sector and the economy overall. Clean energy indexes across the board saw returns well above market benchmarks. For example, the NEX, a global index of publicly traded companies active in renewables and low-carbon energy, gained 53.9% in 2013, far outpacing gains of 29.6% for the S&P 500, 26.5% for the Dow Jones Industrial Average, and 20.3% for the MSCI World & Emerging Markets Index.

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 2013. 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 several 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 fuel 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 PV systems, CHP systems, and stationary fuel cells; it also investigates the current state of the market for CCS, 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 have 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 researchers, reporters, and analysts in 12 countries around the world.

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 energy and environmental markets. Membership organizations and partners 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.

The 2014 edition: second in a series

This report is the second annual production of the Factbook. Last year's report, first published January 2013 and updated in July 2013, can be downloaded [here](#). Compared to the 2013 edition, the 2014 edition keeps intact the structure of the report and the story about a sector in the midst of transformation. For the most part, this year's report represents an update of last year's work. There are, however, some important changes in this most recent edition:

- *Updated analysis:* most charts in the report have been extended by one year to capture the latest data; this includes updated numbers for deployment, financing, and costs of the various technologies. Refreshing these numbers is vital for the report to remain useful, as many of these technologies are evolving and growing rapidly. Cumulative solar capacity in the US, for example, grew by 50% in the course of just one year.
- *2013 developments:* the text in each of the sections highlights major changes that occurred over the past year. While most of the longer-term trends described in the 2013 Factbook remain applicable today, the past year saw market developments that, in some cases, cemented, and in

others, bucked, the long-term trends. For instance, after two years of decreasing energy consumption and five years of mostly declining CO2 emissions, both metrics very likely ticked up in 2013. And while shale gas production has expanded on a massive scale and is poised to rise rapidly in the face of increased consumption and on the back of low-cost supply, production of the fuel did not rise as quickly in 2013 as it had in years past.

- *Expanded coverage (bioenergy)*: the report includes updated coverage of all the sectors analyzed in the 2013 edition, plus more extensive coverage of the biogas and waste-to-energy sectors (Section 4.4).
- *New themes*: the last section of the report identifies critical themes that cut across multiple sectors. The 2014 edition contains a new inventory of themes, plus updated figures and insights on themes that carried over from last year's report.

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, biogas, waste-to-energy, 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

	LARGE-SCALE THERMAL / NUCLEAR POWER	RENEWABLE ENERGY	DISTRIBUTED POWER, STORAGE, EFFICIENCY	TRANSPORT
SUSTAINABLE ENERGY (as defined in this report)	<ul style="list-style-type: none"> •Natural gas •CCS 	<ul style="list-style-type: none"> •Solar •Wind •Geothermal •Hydro •Biomass •Biogas •Waste-to-energy 	<ul style="list-style-type: none"> •Small-scale renewables •CHP and WHP •Fuel cells •Storage •Smart grid / demand response •Building efficiency •Industrial efficiency (aluminum) •Direct use applications for natural gas 	<ul style="list-style-type: none"> •Electric vehicles (including hybrids) •Natural gas vehicles
OTHER CLEAN ENERGY (not covered in this report)	<ul style="list-style-type: none"> •Nuclear 	<ul style="list-style-type: none"> •Wave / tidal 	<ul style="list-style-type: none"> •Lighting •Industrial efficiency (other industries) 	<ul style="list-style-type: none"> •Biofuels

Source: Bloomberg New Energy Finance, Business Council for Sustainable Energy

SECTION 2. A LOOK ACROSS THE US ENERGY SECTOR

US energy consumption patterns continue to change in both the transport and power sectors. New regulations on vehicles and development of new technologies are keeping the consumption of petroleum-based fuels in check. On the power generation side, coal for decades served as the workhorse but has seen its share decline at the expense of natural gas and renewables. Natural gas's contribution to US power grew from 22% to 28% from 2007 through 2013. Renewable energy is also growing quickly; total installed capacity (excluding hydropower) more than doubled between 2008 and 2013, from 44GW to 92GW. Meanwhile, more efficient use of energy has restrained overall electricity demand growth.

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

Total annual energy consumption fell 5.0% from 2007 to 2013, driven in part by advances in energy efficiency. This decrease occurred despite an economy that grew over the same period. Even with a major recession, US GDP is estimated to have been 6.0% larger in 2013 than in 2007. In 2013, GDP growth (expected to be around 1.9%) may well have outpaced energy growth (1.4%), though GDP estimates can be subject to major later revisions. While energy use overall is falling, the use of natural gas and renewable energy has increased, and 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 2013, and renewables (including hydropower) supplied 9.5% (Figure 2). Much of the overall energy reduction has come from sectors outside electricity, 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, 1990-2013

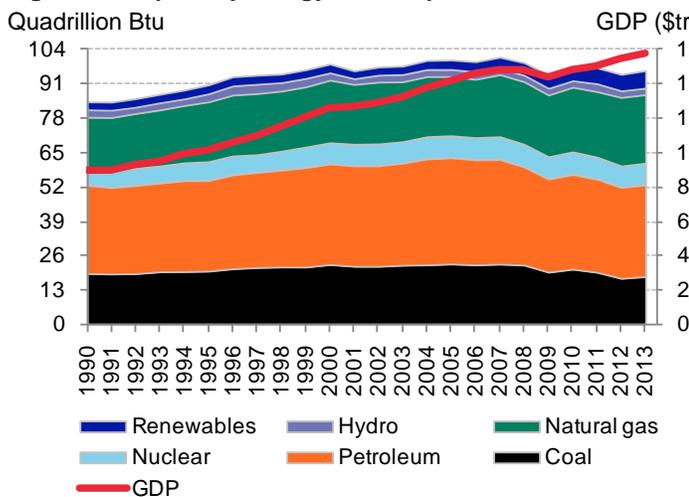
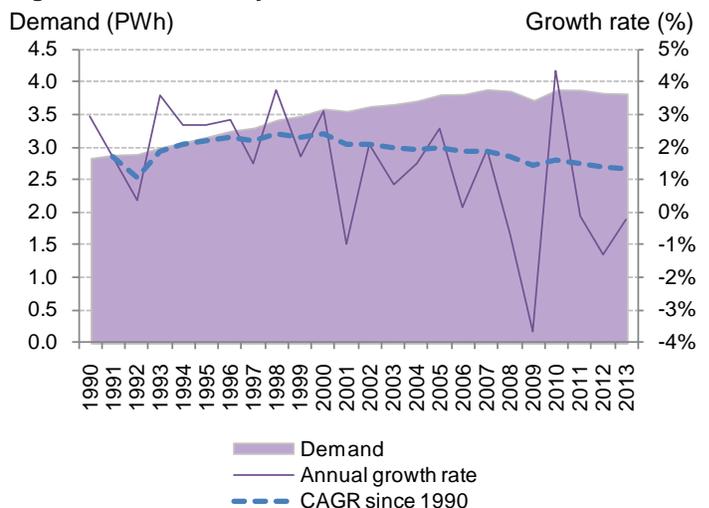


Figure 3: US electricity demand, 1990-2013



Source: Bloomberg New Energy Finance, Bureau of Economic Analysis (BEA), US Energy Information Administration (EIA). Note: GDP is real and chained (2009 dollars); annual growth rate for GDP in 2013 is based on BEA press release from 30 January 2014 (that figure is subject to revision). PWh stands for petawatt-hours (billion MWh). CAGR is compounded annual growth rate. Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2013).

Over 1990-2013, while total energy consumption grew by a compound annual growth rate (CAGR) of just 0.6%, electricity demand grew more than twice as quickly at 1.3%. But the rate of growth has been decreasing and five of the past six years have actually seen declines (Figure 3) in demand.

The mix of fuel sources providing that electricity has also been changing. Natural gas-fired power plants provided 28% of US electricity in 2013 – up from just 22% in 2007 (though down from the record year of 2012, when 31% came from natural gas). Meanwhile renewable electricity generation, including hydropower, has grown from 8.3% to 12.9% 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. This substitution is possible for two reasons:

- 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. This explains 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.

Figure 4: US electricity generation by fuel type, 2007-13 (%)

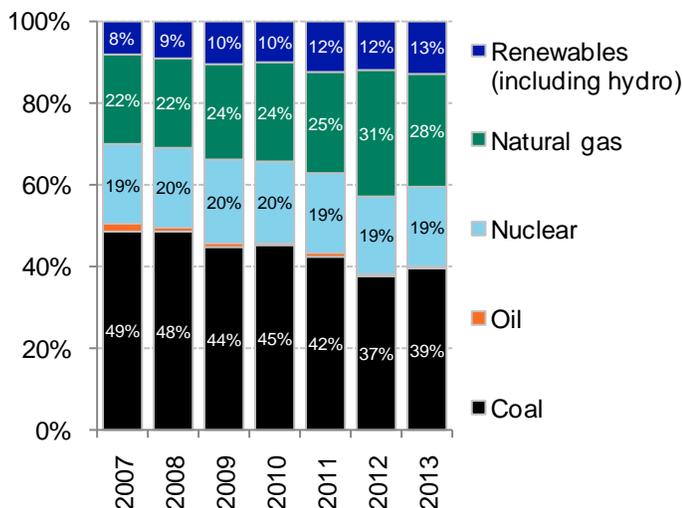
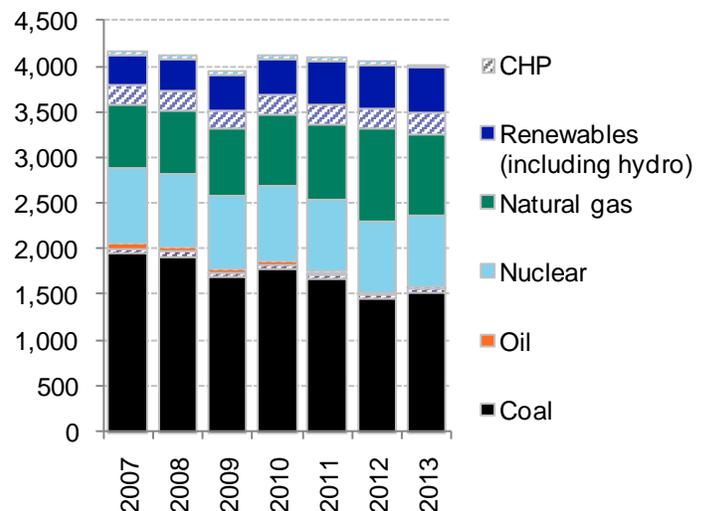


Figure 5: US electricity generation by fuel type, 2007-13 (TWh)

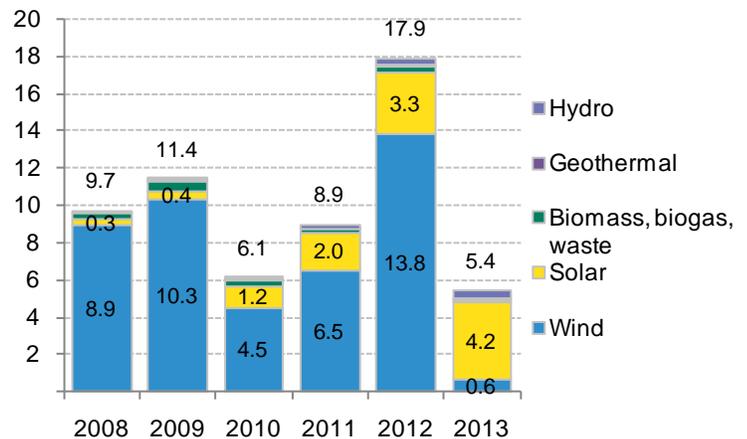
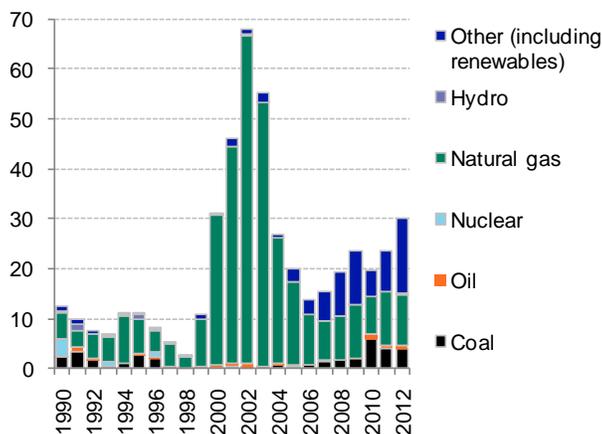


Source: Bloomberg New Energy Finance, EIA Notes: In Figure 4, contribution from 'Other' is not shown; the amount is minimal (<0.4%) and consists of miscellaneous technologies including hydrogen and non-renewable waste. In Figure 5, contribution from CHP is indicated by a 'shaded' bar in the columns. The hydropower portion of 'Renewables' includes negative generation from pumped storage. Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2013).

These factors have made natural gas one of the two fuels of choice for new build. The other has been renewables. With the help of government incentives, renewable energy project developers have been able to offer utilities exceptionally attractive economics in recent years. Taken together, natural gas and renewables have accounted for 94% of new build since 1997 (Figure 6).

In 2012, renewables represented the largest single source of new capacity growth, with close to 18GW added. Of this volume, 13.8GW came from the wind industry, as its key incentive, the Production Tax Credit (PTC), was on the verge of expiring (Figure 7). In 2013, new build dropped to an estimated 5.4GW. Renewable sectors other than solar had been hit hard by the uncertainty that had lingered throughout 2012 over the fate of an important incentive for renewables. Though the incentive was renewed at the beginning of 2013, it has taken a while for project developers to reconstitute their pipelines and refresh the wave of financing activity. PV, on the other hand, had its best year yet and for the first time surpassed wind in terms of annual capacity build.

Figure 6: US capacity build by fuel type, 1990-2012 (GW) **Figure 7: US renewable capacity build by technology, 2008-13 (GW)**



Source: Bloomberg New Energy Finance, EIA, FERC Note: In Figure 6, numbers for official capacity additions for non-renewable energy not yet available. New natural gas build also includes oil-generating capacity; the EIA does not differentiate between the two, but the vast majority is devoted to natural gas generation. In Figure 7, numbers include utility-scale projects of all types, small-scale solar, and small- and medium-sized wind. Wind build in 2013 was in the range of 0.6-1.1GW; final numbers are not yet available, and the conservative estimate is shown here.

Cumulative installed renewable electricity capacity (not including hydropower) more than doubled between 2008 (44GW) and 2013 (92GW) (Figure 9) and renewable electricity generation from these sources increased from 126TWh in 2008 to 255TWh in 2013 (Figure 11).

Including the contributions from hydropower, renewable electricity capacity is now at 192GW and generation has grown to 518TWh. Hydropower has historically provided most of this generation, but 2014 will probably be the first year that generation from large hydropower is eclipsed by generation from other renewable sources.

Figure 8: US cumulative renewable capacity by technology (including hydropower), 2008-13 (GW)

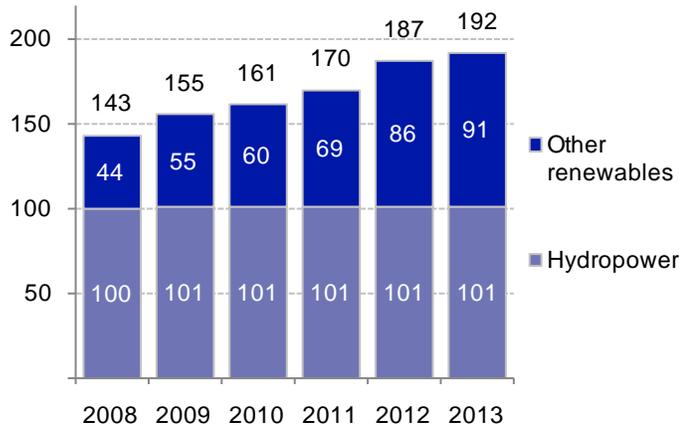
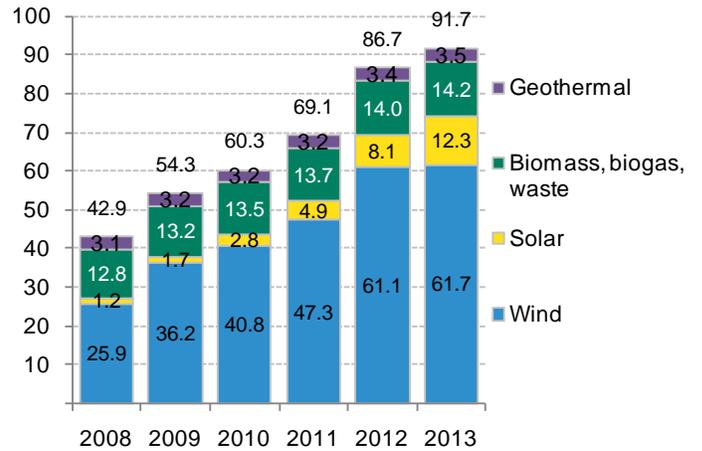


Figure 9: US cumulative non-hydropower renewable capacity by technology, 2008-13 (GW)



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

Figure 10: US renewable generation by technology (including hydropower), 2008-13 (TWh)

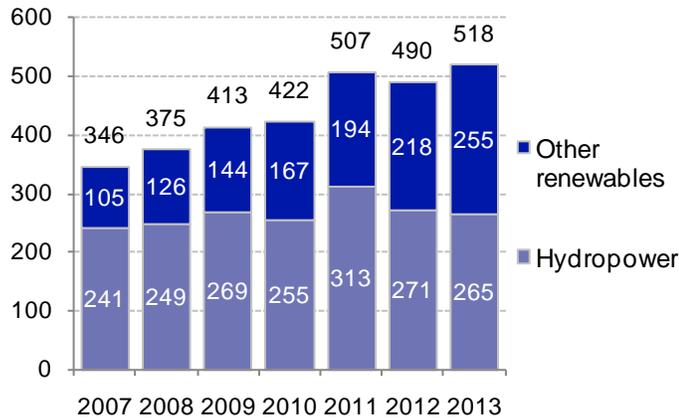
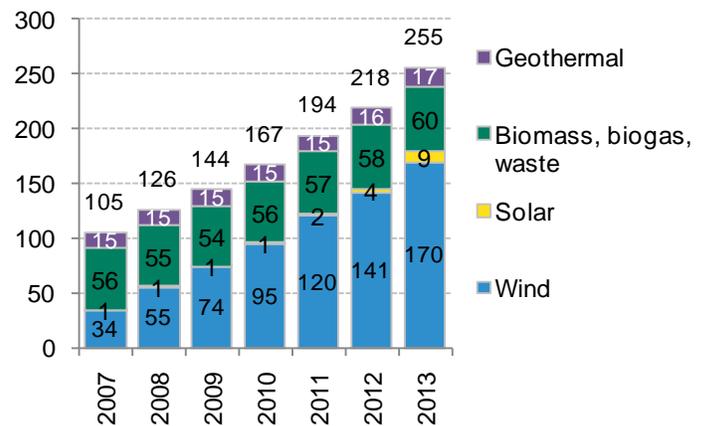


Figure 11: US non-hydropower renewable generation by technology, 2008-13 (TWh)



Source: Bloomberg New Energy Finance, EIA Note: Includes net energy consumption by pumped hydropower storage facilities. Does not include generation from small distributed resources, such as residential PV. Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2013).

2.2. Policy

US sustainable energy policy is in transition from the economic stimulus era of 2009-12, during which the government made available \$66bn in the form of tax incentives, grants, loans and loan guarantees to many of the sectors covered in this report. These supports played a critical role in spurring clean energy deployment during the recession and the challenging few years that followed.

More recently, the Obama administration's policy has focused on making permanent the country's recession-era declines in GHG emissions and hitting longer-terms targets for emission reductions. In 2012, the US adopted vehicle fuel-efficiency standards that aim to cut 2025 GHG emissions (on a per-mile basis) about 75% from their 2010 levels. In 2013, President Obama unveiled his Climate Action Plan, including initiatives to reduce emissions, improve energy efficiency, accelerate renewable penetration and promote the use of nuclear power and natural gas. At the forefront of the broad-

sweeping initiative is a directive to the US Environmental Protection Agency (EPA) to propose greenhouse gas limits on *existing* power plants by mid-2014. Once published, these guidelines could spark controversy just as standards for new-build power plants did in 2013. (More on these standards in Section 5.7, and more on the President's policy in Section 8.1.)

The US Department of Energy (DOE) has been another channel through which the administration has pursued sustainable energy policies. The DOE's loan programs have enabled sponsors of "clean energy projects" to access capital at favorable interest rates. These have consisted of the '1703' program for innovative pre-commercial technologies and the '1705' variant, initiated in the wake of the financial crisis in 2009, for commercial generation and manufacturing projects. Under these programs, plus a direct loan facility, the US to date has provided \$32bn in support for renewables and advanced vehicle technologies. In 2013, the DOE issued a solicitation for proposals for up to \$8bn in loan guarantees for "advanced fossil" technologies, including CCS and innovative natural gas utilization. It also has several billion dollars in remaining authority for renewable energy loan guarantees; the agency expects to seek qualified borrowers in 2014.

The US has no national targets for expanding sustainable generating capacity, and Congress has made no major progress on establishing a carbon cap-and-trade system since such an effort failed in 2009. At the regional and state level, however, there have been considerable efforts to implement policies which have lent strong support for industries in sustainable energy, such as renewable portfolio standards (mandates for renewable energy generation, now on the books in a majority of states) and carbon markets (cap-and-trade programs, which have been adopted in California and nine states across the Northeast and Mid-Atlantic).

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.

At the federal level, the country's grid regulator, the Federal Energy Regulatory Commission, is in the midst of implementing its landmark Order 1000, which allocates the costs of transmission lines to deliver renewable energy to demand centers. The process has been contentious, as utilities and their ratepayers in the regions traversed have resisted paying for facilities that do not benefit them directly.

Further discussion of the specific policies supporting the distinct technologies covered in this report is presented in the sections corresponding to each of those technologies.

2.3. Finance

Bloomberg New Energy Finance has been tracking investments in clean energy globally since 2004. In the US, deal flow slowed due to the 2008 financial crisis but investment volume then rebounded and grew from 2009-11 in part due to stimulus support and increased cost competitiveness. US clean energy investment then slid in 2012 after important incentives for renewables projects lapsed and the continuation of others was uncertain. Sector investment in 2013 fell further, to \$48.4bn (Figure 12).

Asset financing consists of the funding of projects and plants (Figure 13). These investments experienced a spike in 2011 as developers closed financing prior to the expiration of key incentives associated with the federal stimulus program. In terms of sectors, 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, and in 2011-12 as developers sought to take advantage of an expiring tax credit. Though Congress extended the credit at the beginning of 2013, it has taken developers some time to reconstitute their pipelines. Wind investment finished the year strong in 2013, after scarce activity in the first three quarters, but other technologies with longer development timelines, such as hydropower and geothermal, have not yet seen a financing rebound.

Incentives, plunging costs for modules, successful deployments of large utility-scale projects, and creative business models for small-scale deployment have helped turn the focus toward solar in recent years.

Figure 12: Total new US investment in clean energy, 2004-13 (\$bn)

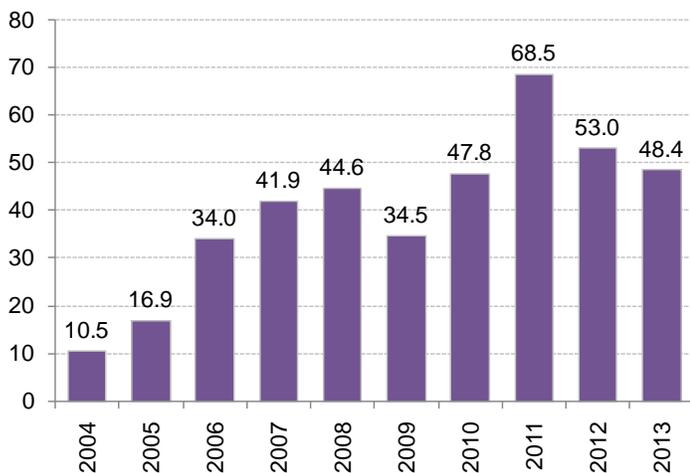
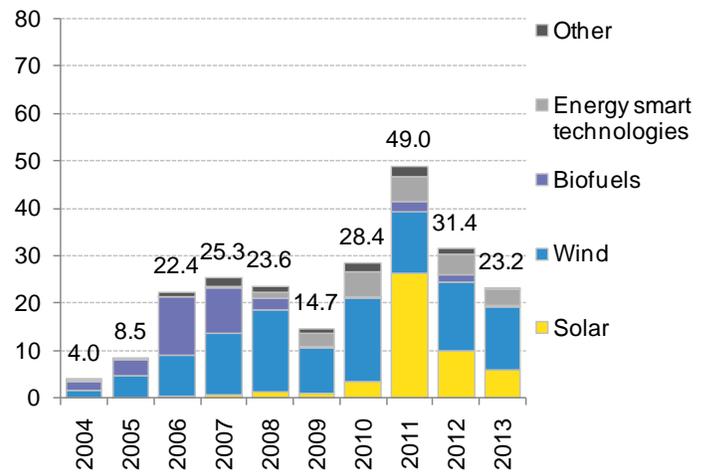


Figure 13: US asset (large-scale project) finance investment in clean energy by sector, 2004-13 (\$bn)



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. Values are in nominal dollars and are not normalized in any way. Clean energy here means: renewable energy, energy smart technologies (digital energy, energy storage, advanced transportation), and other low-carbon technologies and activities (carbon markets value chain, companies providing services to the clean energy industry).

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 over \$37bn in clean energy (Figure 14). The investment numbers have been sagging since 2010, though, and the mix has tilted heavily toward energy smart technology plays.

Public markets suffered dismally in recent years (Figure 15), but saw a major rebound in 2013 as companies took advantage of favorable equity market conditions to raise new capital. Year-on-year public market volumes more than quadrupled in 2013, hitting \$6.8bn and marking the sector’s best year since 2010. Key transactions in 2013 included over \$1bn in secondary equity and convertible bond issues from electric vehicle manufacturer Tesla, a \$92.9m IPO from smart grid company Silver Spring Networks, and a \$352m IPO from wind developer and operator Pattern Energy Group. This last transaction, allowing investors in the public markets to become owners of Pattern’s wind assets, is notable as it provides an example of a ‘yieldco’, an emerging trend in renewable energy finance (more on this in Section 8.5).

Figure 14: US VC/PE investment in clean energy by sector, 2004-13 (\$bn)

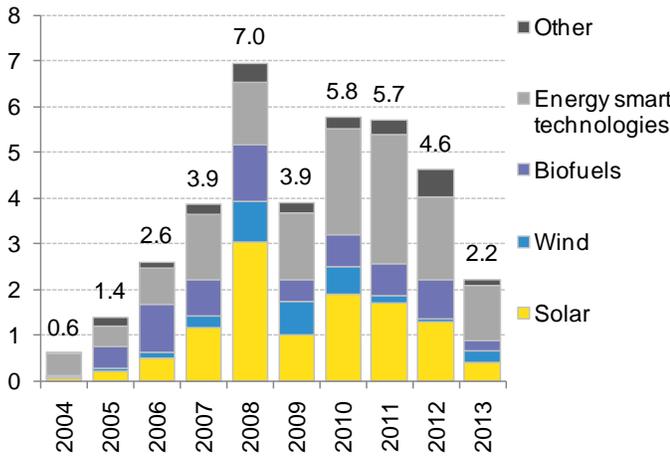
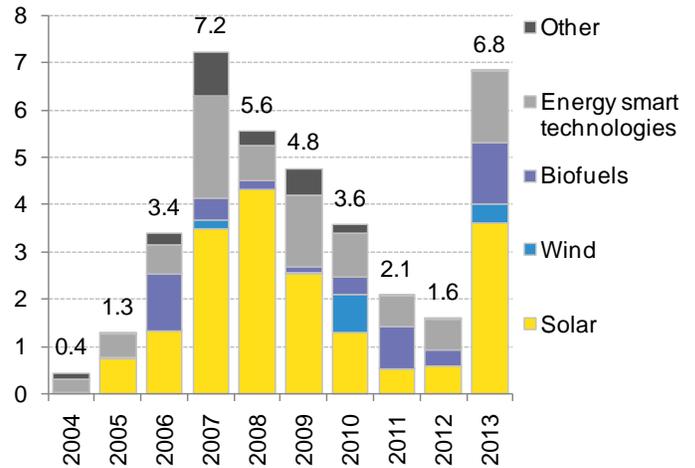


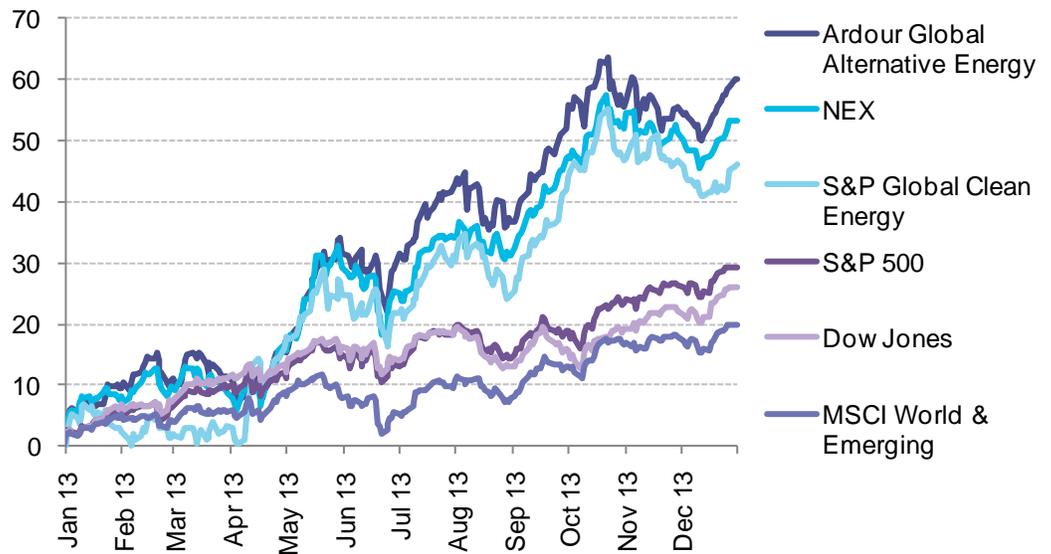
Figure 15: US public market investment in clean energy by sector, 2004-13 (\$bn)



Source: Bloomberg New Energy Finance Notes: See Figure 12 for definition of 'clean energy'. Values in Figure 14 include estimates for undisclosed deals.

Meanwhile, the share prices for many publicly traded clean energy companies surged in 2013, a reflection of greater investor confidence both in the sector and the economy overall. Clean energy indexes across the board saw returns well above market benchmarks. For example, the NEX, a global index of publicly traded companies active in renewables and low-carbon energy, gained 53.9% in 2013, far outpacing gains of 29.6% for the S&P 500, 26.5% for the Dow Jones Industrial Average, and 20.3% for the MSCI World & Emerging Markets Index. US companies that saw major increases in their valuation in 2013 include PV manufacturer SunPower, third-party solar financier and installer SolarCity and electric vehicle manufacturer Tesla.

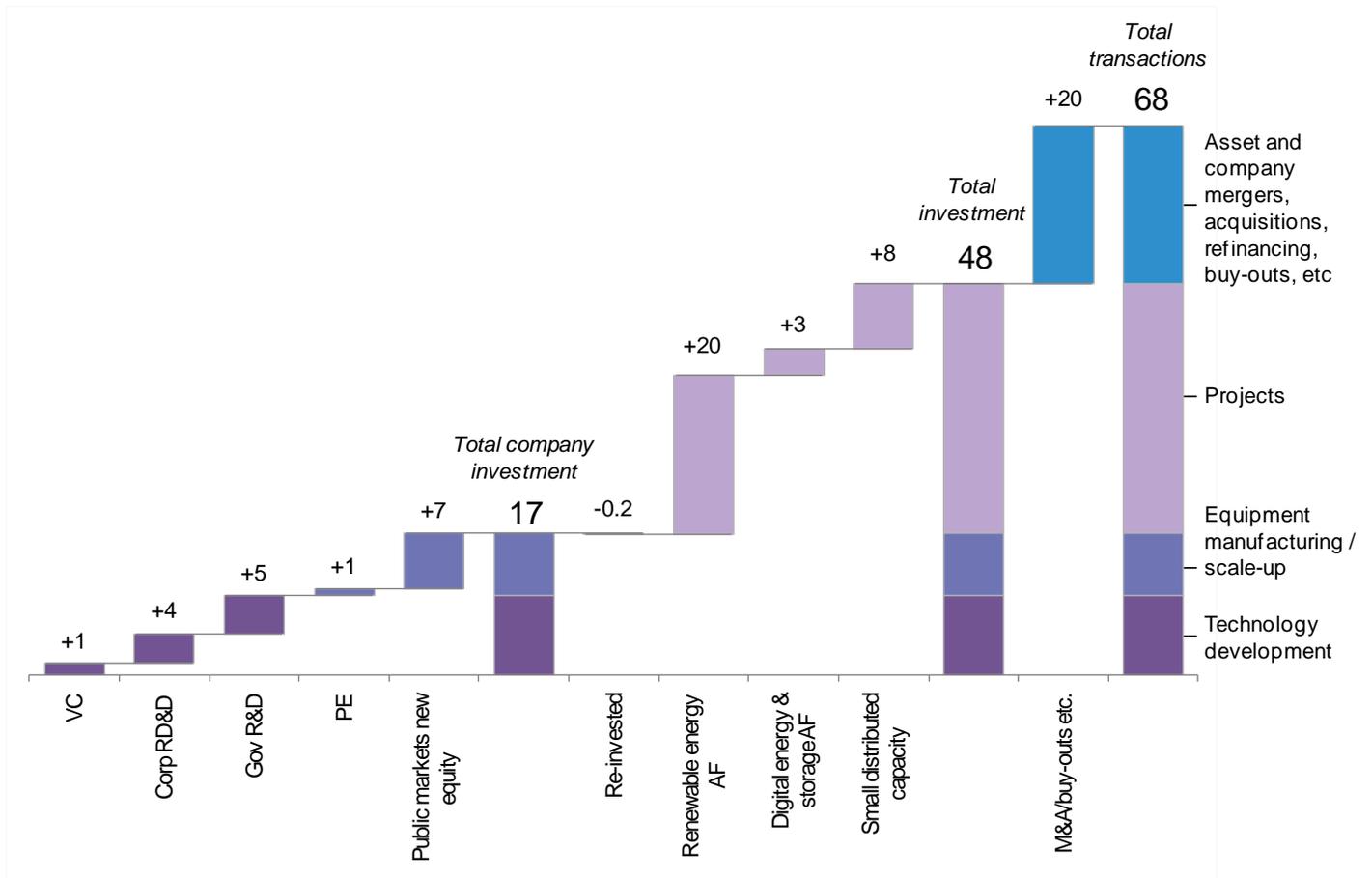
Figure 16: Returns of clean energy indexes relative to benchmark indexes (%)



Source: Bloomberg New Energy Finance

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, 2013 (\$bn) (as per Bloomberg New Energy Finance definition of clean energy)

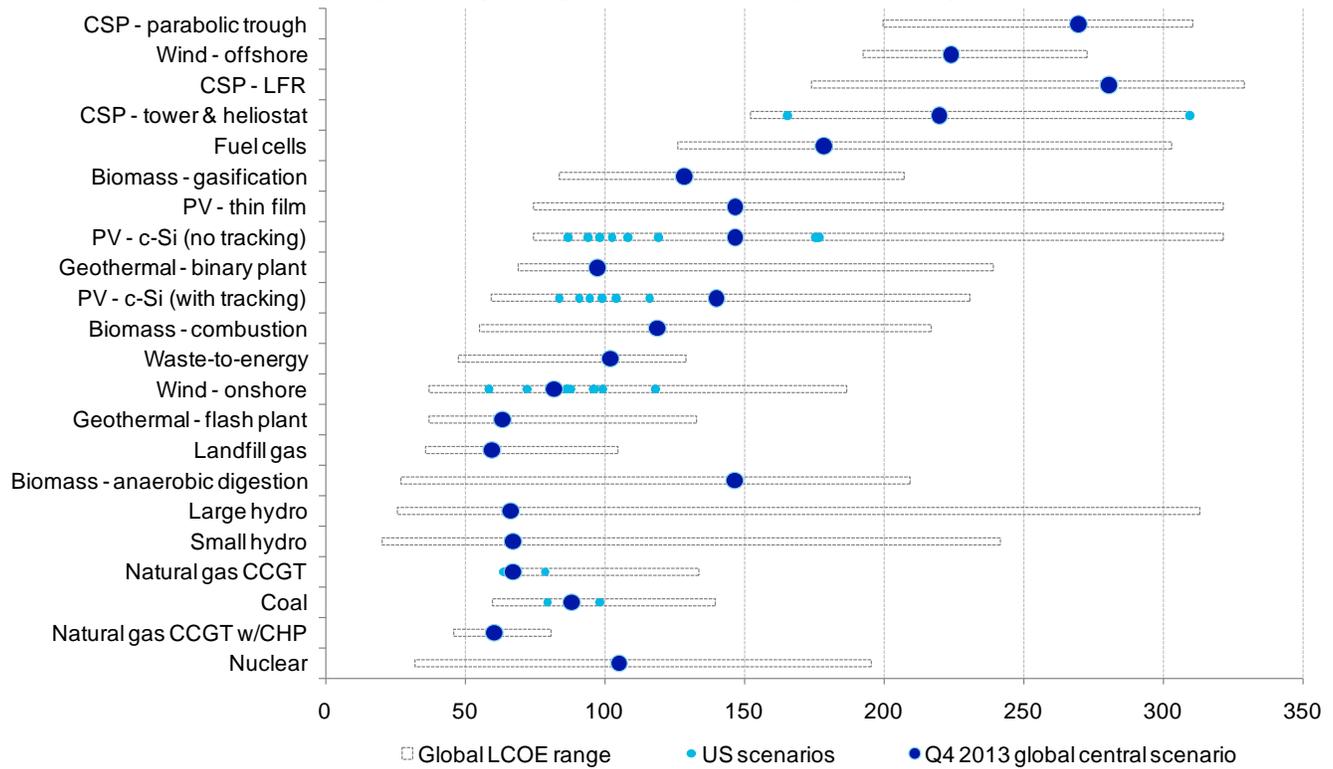


Source: Bloomberg New Energy Finance. Notes: See Figure 12 for definition of 'clean energy'. 'AF' refers to asset finance.

2.4. Economics

The Bloomberg New Energy Finance levelized cost of electricity (LCOE) analysis compares the cost of producing electricity from 22 technologies, and incorporates the costs of equipment, capital, and operation (Figure 18). Dark-colored circles show global central-case scenarios; the lighter-colored show LCOEs of specific US projects. These figures reflect 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; even more of them are viable when accounting for incentives (not shown). The economics of specific technologies are further analyzed throughout this report.

Figure 18: Levelized cost of electricity across power generation technologies, Q4 2013 (\$/MWh)



Source: Bloomberg New Energy Finance, EIA Notes: LCOE is the per-MWh inflation-adjusted lifecycle cost of producing electricity from a technology assuming a certain hurdle rate (ie, after-tax, equity internal rate of return, or IRR). The target IRR used for this analysis is 10% across all technologies. 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% after-tax equity IRR for project sponsor. The dark-colored circles correspond to a global central scenario, with the exception of nuclear, gas, and coal – where the light blue circles correspond to US-specific scenarios; there are multiple light blue circles per technology, corresponding to different projects, with varying economics, that have been installed in the US across different regions. 'CHP' stands for combined heat and power; 'CCGT' stands for combined cycle gas turbine; 'c-Si' stands for crystalline silicon; 'CSP' stands for concentrated solar power; 'LFR' stands for linear Fresnel reflector.

SECTION 3. NATURAL GAS

In just half a decade, conventional wisdom surrounding US natural gas has taken a 180-degree turn. As recently as 2005, companies spent billions on import facilities in preparation for the inevitable decline of US natural gas production. Today, improved hydraulic fracturing and horizontal drilling techniques are unlocking a bounty of shale and tight natural gas. The industry is even preparing for a future in which the US would be a major exporter of natural gas.

Natural gas consumption and production have both grown significantly over the last five years, though production is currently outpacing demand. Additional consumption will eventually materialize, as coal plants retire, new manufacturing facilities begin operation, and LNG terminals start exporting natural gas abroad. In the meantime, producers are focusing more efforts and budgets on oil-prone, rather than dry gas, plays, as the US remakes itself as an oil producer. Meanwhile, technological progress and the wind-down in leasehold drilling (ie, drilling to hold acreage) have contributed to operational efficiencies and a lower cost of supply. Because of this, gas prices have remained range-bound around \$3.50-5.00/MMBtu.

3.1. Policy

Drilling technology has improved very quickly and brought with it an enormous amount of activity. To some degree, regulators are doing their best to catch up with a rapidly evolving market. Among the challenges is balancing the potential economic benefits that the natural gas bounty represents with environmental concerns. In addition, policy-makers are confronting the question of how much natural gas should be made available for export and how much should in effect be kept in the US to bolster economic security and 'energy independence'.

Supply

US policies pertaining to natural gas extraction have come mostly at the state level. Some of the largest-producing states have had regulations since before 2013, while others are trying to catch up on regulating the environmental impacts of hydraulic fracturing.

Major natural gas producers such as Pennsylvania and Texas have rules requiring disclosure of chemicals used in hydraulic fracturing. Oklahoma joined their ranks in 2012, adopting chemical disclosure rules that will affect all wells drilled in the state starting in 2014, and related rules have recently been adopted in Ohio, Illinois and California.

Wyoming's Oil and Gas Conservation Commission in November 2013 adopted a regulation requiring producers to conduct baseline water sampling (ie, before and after drilling), which was closely modelled on a rule that Colorado's Rule 609 passed at the end of 2012. The economic impacts of baseline water testing are negligible, with the Petroleum Association of Wyoming estimating incremental costs of just \$15,000 per well. In a somewhat related event, the EPA ended its probe into groundwater contamination at a site in Pavillion, Wyoming where landowners had claimed drilling activity had contaminated drinking water wells.

Colorado also became the first state to pass rules that directly limit methane leakage from fracked oil and gas wells. Its rule goes beyond the EPA's 2012 New Source Performance Standards (NSPS) regulation and mandates the use of 'green completion' equipment on virtually all fracked wells by 1 January 2015 but only regulates volatile organic compounds (VOCs). (Green completion equipment consists mainly of temporary processing units that allow for the water, oil, gas and sand to be separated at the wellhead during the brief but intense flowback period, when the well is producing at very high pressures. The NSPS for VOCs will also reduce methane emissions from natural gas production.)

At the federal level, the Bureau of Land Management has proposed rules governing water quality from hydraulic fracturing on public lands, and in December 2014, the EPA is expected to issue a draft version of a comprehensive report on the impact that fracking has on drinking water resources.

Demand

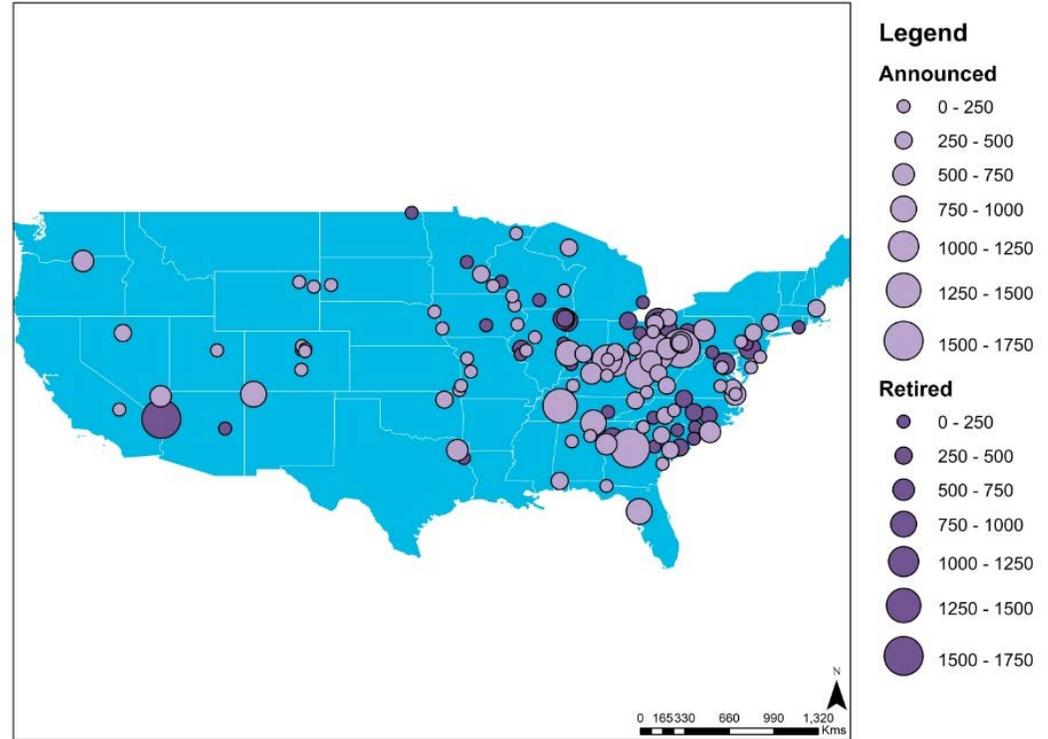
US federal policy is poised in coming years to spur increases in gas demand both domestically and through export, and largely at the expense of coal. The US currently exports just under 2Bcfd of natural gas to Mexico via pipeline (the US also exports to Canada but is an importer from its northern neighbour on a net basis). However, North America is effectively a 'gas island' – insulated from the supply/demand/price dynamics in the rest of the world. This will change in the coming years; policy-makers are currently evaluating more than 20 terminals that would export LNG, on top of the five projects that have already received authorization. (However, authorizations do not equate to exports, and most observers believe only a small proportion of authorized projects ultimately will be built.) Exports to Mexico should also rise rapidly in coming years as border connections are increased and domestic bottlenecks within the Latin American country are removed.

After approving 2.2Bcfd of LNG exports from Cheniere Energy's Sabine Pass terminal in May 2011, the DOE took a two-year hiatus while it commissioned a study on the net economic benefit of US LNG exports and re-assessed its policy stance. (DOE authorization is required to export natural gas to countries with which the US does not have a free trade agreement, which includes most large LNG importers, save South Korea.) In May 2013 it granted its second authorization, to the Freeport terminal in Texas, and proceeded to grant four more: to the Lake Charles project in Louisiana, Cove Point in Maryland, an expansion at Freeport, and Cameron in Louisiana. In all, the DOE had authorized 8.47Bcfd of LNG exports as of February 2014.

Policies directed at coal-fired power plants are also having an enormous effect on the gas sector. EPA regulations will require existing coal facilities to install expensive technologies to reduce emissions of 'criteria pollutants', which include sulfur dioxide, nitrogen oxides and mercury. Chief among these rules is the Mercury and Air Toxics Standard (MATS), for which compliance takes effect in 2015. (More on the EPA regulations in Section 8.1.)

These policies, along with old age and thinner margins due to less expensive gas, have prompted the retirement of 13.9GW of coal plants since January 2011. A further 32.5GW have announced their intention to retire, and more are sure to come (Figure 19). The result will be increased reliance on new and existing gas plants for both mid-merit and baseload power generation.

Figure 19: US coal power plant retirements completed and announced, 2011-2013



Source: Bloomberg New Energy Finance, ESRI, EIA Note: Includes capacity which has retired in 2011-13 or announced a date for retirement as of December 2013.

The EPA New Source Performance Standards for GHG emissions from new power plants will further support power sector gas demand by effectively preventing any new coal build without CCS storage (Section 5.7). New CCGTs, in contrast, are already largely compliant with the standard.

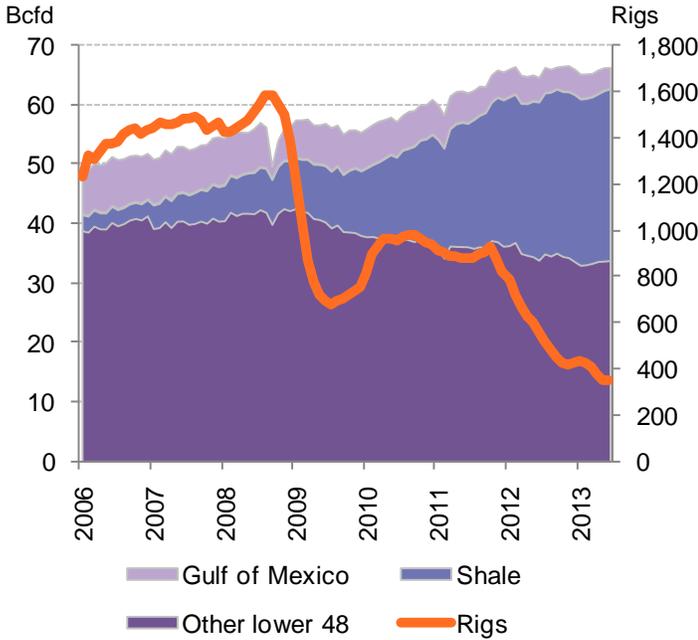
3.2. Development

Supply

Despite falling rig counts and low gas prices, production continued to grow in 2013, though at a substantially slower pace (0.6%) than in recent years (7% growth in 2011 and 2012) (Figure 20). Two main factors accounted for this seeming contradiction. First, many areas are economical even with gas prices below \$4/MMBtu. Most of these derive substantial value from oil or natural gas liquids (NGLs) production, but certain dry gas areas exhibit solid rates of return due to high production/low well costs.

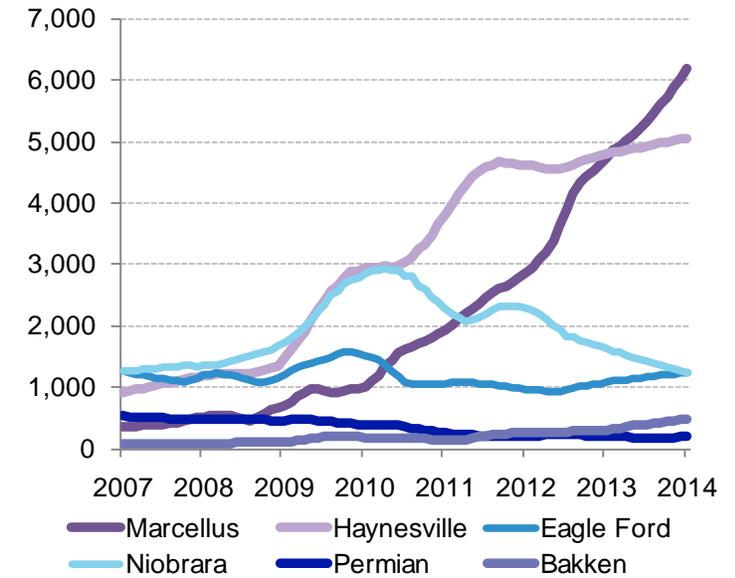
Second, rigs are drilling wells more quickly than ever. As a result, lower rig counts do not necessarily translate into fewer new wells brought online. In recognition of this, the Energy Information Administration (EIA) began in October 2013 releasing its Drilling Productivity Report, which uses data not just on rig counts, but on well counts and oil and gas production by county as well to provide a better productivity metric (Figure 21).

Figure 20: US dry natural gas production and gas-directed rig count, 2006-2013



Source: Bloomberg New Energy Finance, EIA, Baker Hughes

Figure 21: Gas production per rig (mcf/d)

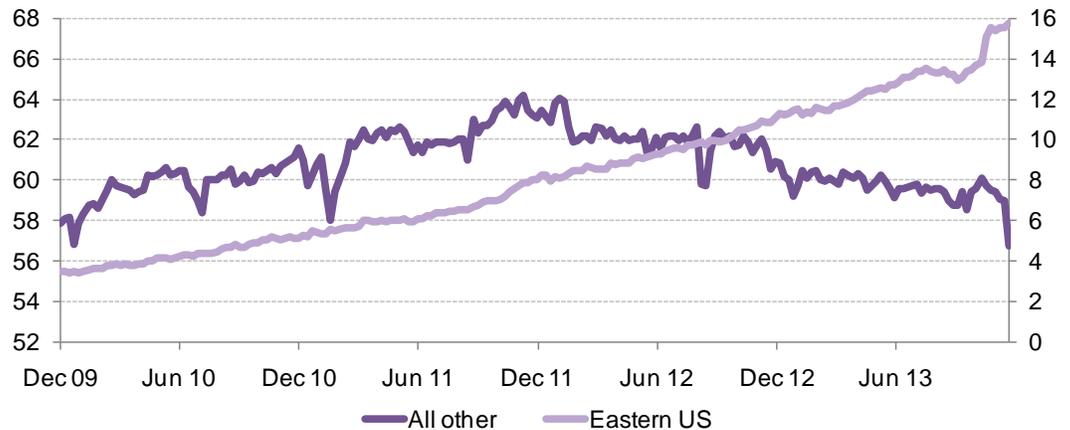


Source: Bloomberg New Energy Finance, EIA

On both of the above, the Marcellus shale is the clear standout. It houses the most economical dry gas play in the country and has seen the fastest improvement in rig productivity. It is thus not surprising that the Marcellus has singlehandedly more than offset declines in dry gas production from elsewhere in the US (Figure 22).

Production declines outside of the Marcellus have been driven by changing economics, causing producers to turn away from some dry gas plays and toward areas like the Marcellus, as well as liquids-rich plays like Eagle Ford and Bakken. Another factor has been the drop in conventional gas production. Higher gas prices could see a resurgence of drilling in dry gas plays and bring greater levels of production in the future.

Figure 22: Gas production in the continental US (Bcfd)



Source: Bloomberg New Energy Finance, LCI Energy Note: Eastern US production is mostly comprised of output from the Marcellus shale.

The vast US pipeline system has continued to grow to keep pace with new natural gas volumes and to connect producers, particularly in the new shale plays, to consumers (Figure 23). For distribution lines, over time, safety upgrades and system expansion has resulted in increasing miles of plastic and protected steel pipeline installation, which has increased safety and reduced emissions¹ as cast iron and unprotected steel pipelines have been replaced (Figure 24).

Figure 23: Existing natural gas distribution pipeline, 1990-2012 (million miles)

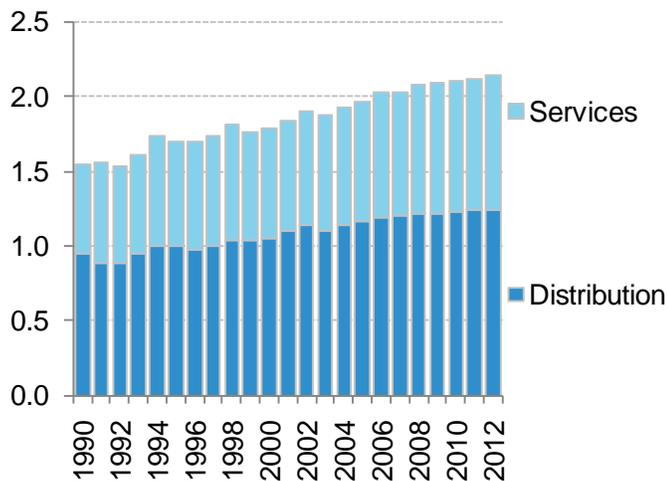
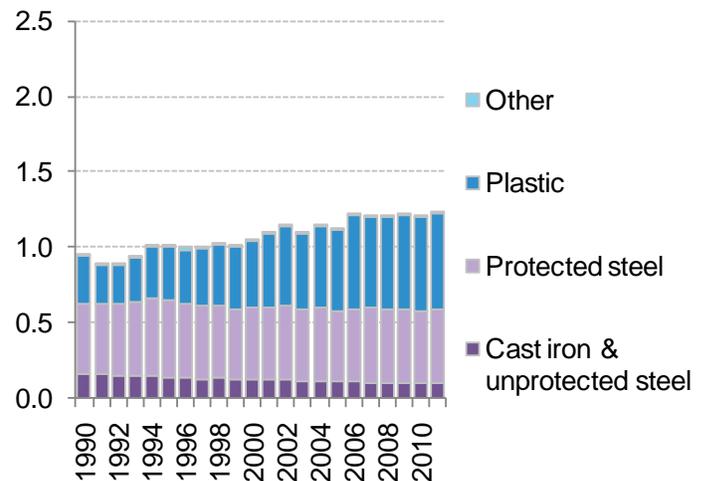


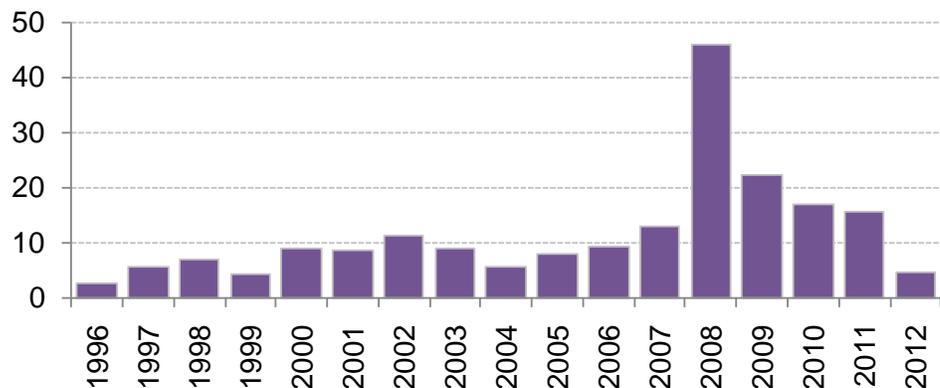
Figure 24: Natural gas distribution mainline material, 1990-2012 (million miles)



Source: Bloomberg New Energy Finance, Department of Transportation, American Gas Association Note: 'Gathering' refers to pipelines which transport natural gas from individual wells to compressor stations, processing points, or main trunk pipelines. 'Transmission' refers to pipelines which transmit gas from sources of supply to distribution centres, to large-volume customers, or to a pipeline installed to interconnect sources of supply. (Transmission lines differ from distribution pipelines in that they operate at higher pressures, are longer, and the distance between connections is greater.) 'Distribution' refers to pipelines to which customers' service lines are attached; 'Services' refer to pipes which carry gas from the distribution pipelines to the customer's meter. In 'Gathering' amounts are very small relative to the total amount and are difficult to see in chart. Numbers are not available for 2013 (Figure 23) or for 2012-13 (Figure 24).

Just as distribution systems are expanding, pipeline operators are consistently expanding the transmission pipeline capacity. For high-pressure, interstate transmission lines, construction largely has shifted away from large, new greenfield pipelines to more discrete capacity addition projects that allow new supply areas to be connected to the broader national pipeline network (Figure 25).

Figure 25: US natural gas transmission pipeline capacity additions, 1996-2012 (Bcfd)



Source: EIA Notes: Figures are based on regulatory filings, industry information and company reports.

1 'Pipeline miles by material' is how the EPA estimates methane emissions from the distribution sector.

Pipelines are being developed to overcome bottlenecks. For example, Spectra Energy put into service the New Jersey-New York Expansion project, which brought 800,000Mcf/day of new pipeline capacity to the New York City area, the first major capacity addition to the area in more than a decade. Still, while new projects such as these continue to get built at a rapid pace, there is still a scarcity of takeaway capacity in key production areas.

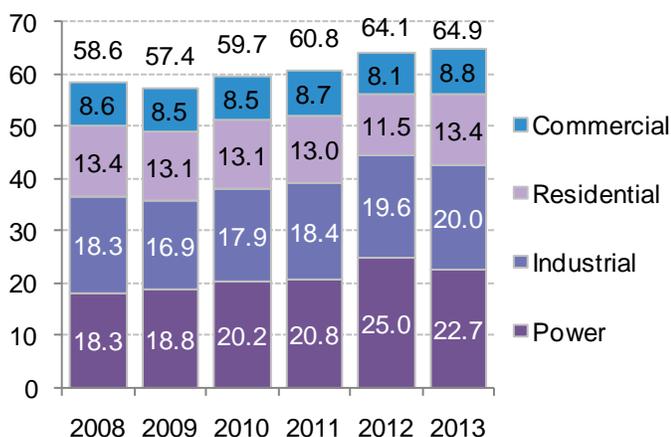
Demand

Natural gas consumption can come from the power sector (natural gas burned to generate electricity), the residential and commercial sectors (natural gas as a heating fuel), the industrial sector (natural gas used as a feedstock for industrial processes, and as a fuel to provide electric or thermal energy to those facilities), and the transport sector (natural gas used as a transport fuel in vehicles equipped for that purpose, described in more detail in Section 7.2).

All of these have been impacted by the changing economics of natural gas. With US natural gas prices expected to remain below global levels, these economics have piqued the interests of energy-intensive industrial consumers. Low prices have also made natural gas the fuel of choice for new power plant build, spurred fuel-switching for homes and businesses, and captured the attention of fuel-hungry transport industries. It has even led several companies to file for permission to export LNG.

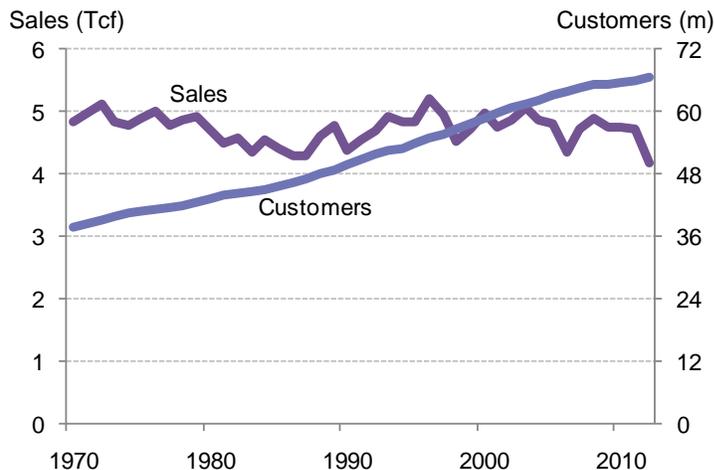
Looking sector by sector, total annual US demand rose in 2013 to its highest level ever, despite power sector consumption dropping by around 9%. This fall is due to higher gas prices in 2013 than in 2012, when a record mild winter led to very low heating demand, incentivizing the price-sensitive power sector to burn off the ensuing storage glut (Figure 26). In the residential and commercial sectors, improvements in energy efficiency have left volumes flat even as the number of residential customers has risen steadily (Figure 27).

Figure 26: US natural gas demand by end-use, 2008-13 (Bcfd)



Source: Bloomberg New Energy Finance, EIA

Figure 27: US natural gas residential customers vs. residential consumption

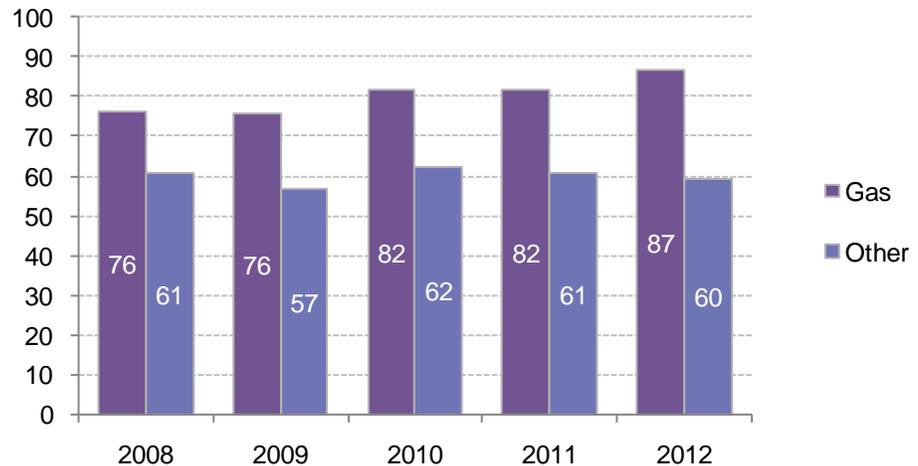


Source: Bloomberg New Energy Finance, American Gas Association

Future growth should continue to come from the power sector as well as from industrial consumers, which are beginning to adjust to the 'new normal' but typically take longer to respond to low prices because of the large capital investments required to build new facilities. However, even as most of these new-build projects are planned for 2015 and beyond, many gas-intense facilities have already restarted or expanded production. Since 2010, there have been 10 restarts or expansions of industrial plants in the US across the gas-intensive ammonia, methanol and ethylene sectors (including six in

2013 alone). Industrial growth has also contributed to increased power sector gas consumption, as on-site generation continues to shift toward gas (Figure 28).

Figure 28: Industrial electricity production from on-site generation by source, 2008-12 (TWh)



Source: Bloomberg New Energy Finance, EIA

3.3. Financing

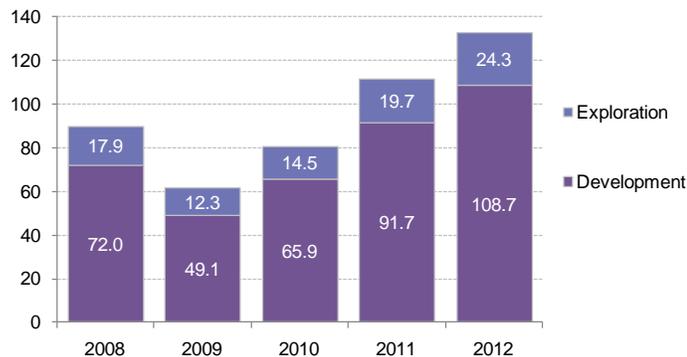
The upstream oil and gas industry continues to attract vast sums of capital, by far the largest of any sector covered in this report. Investments in exploration and production were up in 2012 (the latest year for data are available), while investments in the midstream (mostly pipelines and storage) dropped slightly.

Supply

Investment by North America-focused independent exploration and production companies is on an upward trend (Figure 29). (These numbers include dollars spent on both oil and gas and also some spent internationally and for non-upstream business segments. The figures are limited to independent exploration and production companies because these companies are North America and upstream focussed, rather than integrated oil companies that generally have larger international and downstream business units.) As costs per well have come down, however, producers are now stretching dollars further than in the past.

Investment in natural gas infrastructure fell in 2012 from 2011 levels but remained well above the 2008-10 average (Figure 30). The largest investments were directed toward distribution lines. This is especially the case in the Northeast, where pipeline mileage and capacity is expanding to take advantage of booming Marcellus production. (Infrastructure projects have helped address bottlenecks in the Marcellus and explain the jump in production from the play in November 2013 shown in Figure 22.)

Figure 29: Organic exploration and development spending by independent exploration and production companies, 2008-12 (\$bn)



Source: Bloomberg New Energy Finance Note: 'Independent exploration and production' companies differ from integrated producers and refiners and are generally focussed in North America. 'Organic' refers to the fact that these numbers exclude M&A of assets and companies. The numbers are shown to demonstrate a trend; because the numbers are taken from a selective list of companies, they should not be interpreted as a definitive assessment of market size for upstream spend.

Figure 30: US midstream gas construction expenditures, 2008-12 (\$bn)



Source: American Gas Association Note: Values reflect expenditures reported to the AGA by different types of companies across the supply chain, including transmission companies, investor-owned local distribution companies, and municipal gas utilities. 'General' includes miscellaneous expenditures such as for the construction of administrative buildings.

Demand

The build-out or expansion of gas-intensive industrial plants is evidence that investment has been flowing into the demand side of the US natural gas market. The majority of the new-build ammonia, methanol and olefins crackers that Bloomberg New Energy Finance tracks are fully financed.

To date, the DOE has authorized LNG exports from five locations, which are at different stages of development. At Sabine Pass, at the border of Louisiana and Texas, four liquefaction units ('trains') are fully financed. At Freeport in Texas, \$1.3bn in equity has been secured from IFM Investors and the project expects to complete all fund raising in mid-2014. Developers of the terminal planned for Lake Charles, Louisiana plan to begin raising funds in Q3 2014. Cove Point in Maryland, owned by Dominion Resources, says it has secured financing. Sempra's Cameron LNG project in Louisiana received authorization in February 2014; it expects to secure financing during 2014.

3.4. Economics

Supply

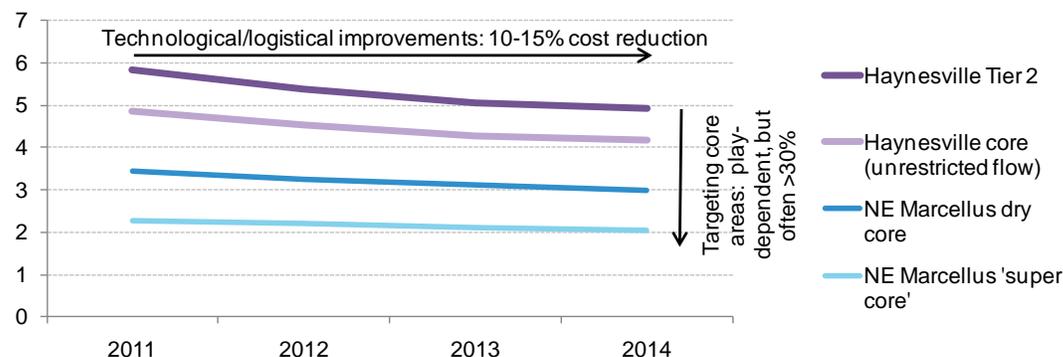
Supply costs associated with natural gas – ie, the cost of extracting it from the ground – have dropped substantially in recent years, due both to technology and logistics improvements and from the effects of better subsurface knowledge. The former can generally be applied across all or many plays, whereas the latter allows producers to target 'sweet spots' with more accuracy, identifying core areas within plays.

On the logistics side, the continued reduction in drilling days (days spent paying for a rig) is due mainly to pad drilling – the practice of drilling many wells from the same pad, often only 20-30 feet apart from one another. When using 'walking' rigs, which can move themselves, well-to-well rig mobilization times may be cut from 10 days to less than one. Even if walking rigs are unavailable or the rig needs to move pads, improved logistics have shaved days – and hence costs – off of drilling.

New chemical products are also improving production rates by improving fracture propagation (ie, the amount of reservoir ‘created’ by fracturing a well) and fracture conductivity (how easily oil and gas can pass through these fractures). They also help lower water transport costs by increasing friction reducers’ salinity tolerance, which allows for higher recycling ratios.

The single largest contributor to reduced supply costs, however, is improved knowledge of the subsurface, which has allowed producers to target extremely productive acreage. In both the northeastern part of the Marcellus Shale and the Haynesville Shale, both of which are dry gas plays, producers have remarkably improved the quantity of natural gas they expect to extract, measured as the estimated ultimate recovery (EUR) of the play. They have done so by honing in on acreage that may flow at four times the rate at which most cost-of-supply estimates were based on in 2011. (For example, Cabot Oil & Gas has wells in the Marcellus that produce over 20MMcfd during the first month, versus many industry ‘rule of thumb’ estimates of initial production rates of 5MMcfd.)

Figure 31: Cost of supply evolution for two plays within the Haynesville and Marcellus , 2011-14 (\$/MMBtu)



Source: Bloomberg New Energy Finance

Demand

This section considers the economics of the two largest natural gas-consuming sectors: power and industry. The economics of a third sector, transport, are covered in Section 7.2. In the power sector, coal-to-gas fuel switching – a very price-sensitive, and hence cyclical, phenomenon – has begun to peter out, as coal prices have remained below natural gas prices in \$/MWh terms since the spring (Figure 32). This metric looks solely at short-run costs, which is appropriate for day-to-day market behavior. However, when undertaking long-term investment decisions, generators also factor in the costs of construction and fixed costs. On this basis, and without including any future carbon price, natural gas looks much more economical than coal (Figure 33).

Figure 32: Cost of generating electricity in the US from natural gas vs. coal, trailing two years (\$/MWh)

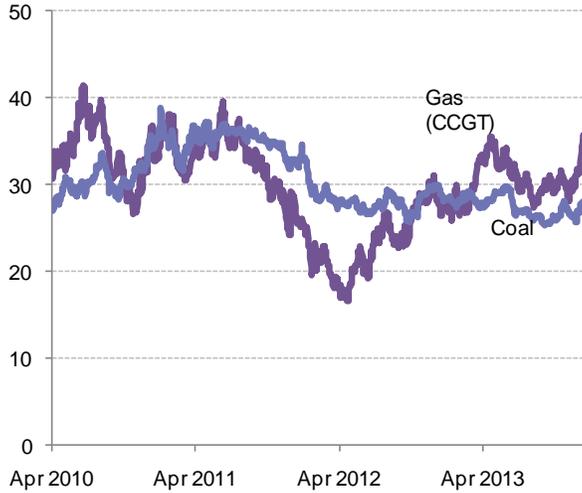
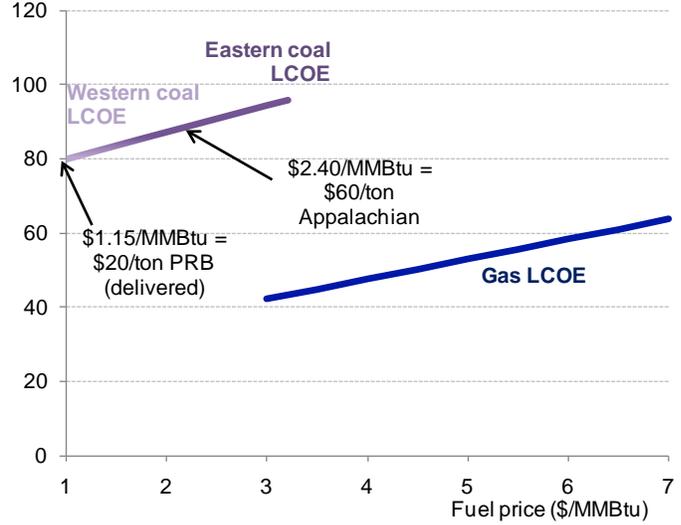


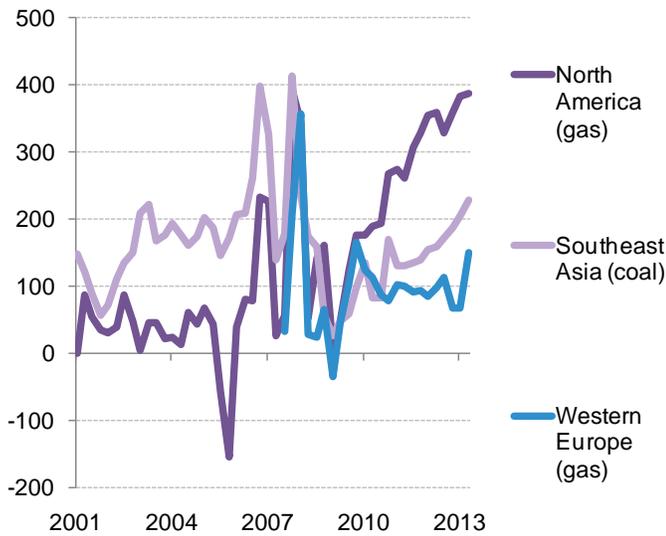
Figure 33: LCOE comparison for natural gas vs. coal (\$/MWh)



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.

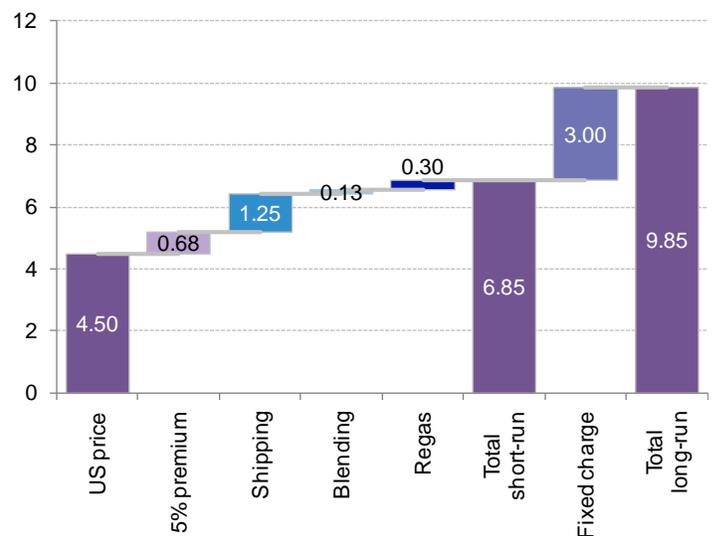
For gas-intense industrials and LNG, the story is about how the US stacks up to the rest of the world, as the outputs are globally traded commodities (Figure 34, Figure 35).

Figure 34: Methanol cash margins by main feedstock (\$/t)



Source: Bloomberg New Energy Finance, Nexant

Figure 35: LNG cost build, US Gulf Coast to Europe (\$/MMBtu)



Source: Bloomberg New Energy Finance Note: 'Regas' is regasification, or the process in which imported LNG is expanded and reconverted into gas that can be injected into the pipeline distribution network. 'Fixed charge' is the cost associated with recouping upfront costs (the other costs shown here are short-run marginal costs).

3.5. Market dynamics

Supply

While there are attractive economics for several dry gas plays, the emphasis remains on oil and heavy NGLs. Virtually every producer's strategy in the short term (1-2 years) is to dedicate capital toward oily plays and away from gassy ones.

Technology-wise, producers continue to drill longer 'laterals' (the horizontal portion of the well), frack more stages, and increase the number of wells drilled per pad site. Additionally, in the many regions where productive oil and gas formations are stacked atop one another, producers are increasingly accessing several layers from the same pad (in the past, a distinct pad was needed for each formation). For example, the Bakken formation is the most famous of a series of oil-producing zones in the Williston Basin, which include three 'benches' of the Three Forks. Meanwhile, in the Permian and Granite Wash, producers may hold acreage that overlay more than five producing formations.

In terms of investment, private equity is playing a larger role in funding the US upstream. This is despite barriers to entry: horizontally drilled and fracked wells are far more expensive to develop than un-stimulated vertical wells, and more of them must be drilled to 'prove' an area, requiring higher initial investment. (As noted earlier, costs per fracked well have come down, but they still remain higher than non-fracked wells.)

Despite this, traditionally more risk-averse capital is making its way into the upstream, in part because risks have been reduced (part of this is due to improved drilling technology/techniques, and part is because shale/tight oil and gas plays are geologically more homogenous over large areas than conventional fields).

Downstream

Gas demand continued to grow over 2013, thanks to ample production and expectations for continued low prices. This growth occurred even as power sector burn dropped 9% compared to 2012, when low gas prices led to record consumption in the sector, and as energy efficiency has reduced gas consumption per capita in the residential and commercial sectors. Instead, a steady growth in new residential customers and the restart and expansion of multiple gas-intensive industrial projects have led to a continued upward trend in US gas consumption.

The bulk of gas demand growth, however, is still to come. US environmental regulations should accelerate the retirement of many coal power plants, and several large projects on the East Coast have already announced retirement dates. This will increase the power sector's reliance on gas generators for baseload power. The industrial sector, which has been slower to respond to low gas prices due to the large capital investments required, is also picking up steam, with planned investments for the rest of the decade dwarfing 2010-12 spending. The first of the nation's proposed LNG export facilities are also on track to start up after 2015. All of this indicates that gas demand is poised to grow even more in upcoming years.

SECTION 4. LARGE-SCALE RENEWABLE ELECTRICITY

Declining capital costs, along with federal incentives and state mandates and incentives, have driven a boom in project development over the last five years, though the year-to-year numbers have been far from consistent. Wind build rocketed to 13.8GW in 2012 and then plummeted to 600MW in 2013 in the aftermath of regulatory uncertainty. Solar build has climbed each year, reaching 4.2GW, including successful deployments of large utility-scale projects, in 2013. The economics of these technologies have never looked more attractive to utilities, which are now signing PPAs below \$70/MWh for solar and in the \$20-35/MWh range for wind. 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 discussion of policies specific to each sector follows. This section looks at large-scale renewable electricity, which in this report is generally defined as projects above 1MW in size. Parts of Section 5 consider smaller-scale installations.

4.1. Policy for all renewables

The US has a patchwork of policies supporting renewable energy generation and deployment. These policies tend to leverage the tax code, which contains incentives for investment in generation projects and favorable mechanisms for cost recovery and depreciation (Table 1).

Among the most significant US policies has been the Production Tax Credit (PTC) which has been used to incentivize sectors such as wind, biomass, biogas, geothermal, and hydropower. The PTC allows qualifying sectors to deduct \$11 or \$23 (depending on the sector) for each megawatt-hour produced over the first decade of a project's operating life. In the case of wind, for example, the PTC helped the sector deploy a record 13.8GW in 2012. For hydropower, 36 distinct projects received certification to earn PTCs over 2012-13. Congress renewed the PTC in January 2013 after the credit very briefly expired at the end of 2012. But the threat of its expiration was enough to stifle investment in 2012, resulting in decreased deployment for several sectors in 2013.² Other than the PTC renewal at the beginning of the year, most other energy-related legislative efforts stalled, with the exception of two bills focused on streamlining hydropower projects.

The January 2013 renewal of the PTC included a significant enhancement: it changed the definition of a qualifying project. In the past, developers had to have their project commissioned by the PTC's expiration date to qualify. Now, such projects must merely be under construction by the expiration date. The change had the intended effect of maintaining the growth of at least the wind sector; it also guarantees that, regardless of whether the PTC is extended or modified again, qualifying projects will continue to come online in 2014 and 2015.

2 Deployment numbers lag investment numbers, since project construction – which typically begins after financing has been received – can take months or years, depending on project size, technology, and complexity.

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 their investment in qualifying property. The solar industry has been the primary beneficiary of this incentive.³

Table 1: 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. For solar, qualifying properties are then eligible to receive 10% incentive thereafter. ITC for other technologies not available after 2016.
		Wind, biomass, geothermal, hydropower, marine, tidal	Must begin construction by end-2013
	Credit equal to 10% of eligible capital expenditure	Geothermal	No expiration
		CHP, microturbines	Must commission by end-2016
Production Tax Credit	10-year production-based credit equal to \$22/MWh (inflation adjusted)	Wind, closed-loop biomass, geothermal	Must begin construction by end-2013
	10-year production-based credit equal to \$11/MWh (inflation adjusted)	Open-loop biomass, landfill gas, waste-to-energy, marine, qualified hydropower and hydrokinetic	Must begin construction by end-2013
Modified Accelerated Cost Recovery System (MACRS) and other depreciation incentives	MACRS allows depreciation of tangible property on an accelerated basis (five years for wind, solar and geothermal and seven years for biomass and marine) 'Superbonus' and 'bonus depreciation allow for even more accelerated schedules	All sectors	MACRS does not expire. Superbonus depreciation (100% in year one) expired at end-2011; bonus depreciation expired at end-2013.

Source: Bloomberg New Energy Finance Notes: Small wind refers to projects 100kW or less. The PTC is also available for solar systems installed by the end of 2005; the combined capacity of these is minimal.

The US tax credits and accelerated depreciation have sustained project development as the tide of federal stimulus recedes. However, those credits and deductions are only useful to companies which need to pay meaningful amounts of taxes on income generated annually. That excludes many project developers whose profits fall short of the incentives' value. Thus the sector has traditionally relied on investment from outside 'tax equity' investors. Such investors, typically financial institutions and utility affiliates with regular and sizable tax liabilities, supply project capital in return for taking a passive ownership interest in the project. That arrangement allows them to capture the pass-through benefit of the tax credits.

The financial crisis of 2008 severely reduced the availability of tax equity. What was a potentially calamitous situation for the industry was averted by the 'cash grant' program established under the American Recovery and Reinvestment Act (ARRA). The Treasury-administered program temporarily allowed renewable project developers to take the value of tax credits in the form of cash payments instead. The Act also created a DOE loan guarantee program (on top of other loan programs that existed previously) for certain clean energy technologies, which guaranteed \$16.1bn of loans for

³ The 'commence construction' modification in the PTC extension in January 2013 does not apply to 'Section 48' (referring to the section of the legislation) technologies – including solar, small wind, CHP, and microturbines.

projects and manufacturers. These ARRA programs were critical for US renewable growth in the post-crisis period; the window for qualifying for them has since closed.

At the state level, legislatures led by both major political parties have taken a long view of sustainable energy. No less than 30 states and territories (including Washington, DC and Puerto Rico) have mandatory renewable portfolio standards (RPS) on their books, requiring that specific amounts of clean electricity be consumed each year. The state mandates have been so successful in driving clean energy development that, for most states, the targets for the next several years are on pace to be met, according to Bloomberg New Energy Finance's analysis of these markets (Table 2). The targets continue to escalate each year for most RPS programs, meaning that more renewable capacity will need to be added to continue to stay on pace with the targets. Still, state-level RPS are not as potent in driving development as they once were. To maintain the growth rates of recent years, states may need to raise their targets.

Table 2: 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	Most utilities are well supplied through 2020. However, large investor-owned utilities may be holding on to their bank of credits, which could force small, public utilities to sign for additional renewable capacity.
PJM	IL, MD, NJ, OH, PA	Making a slow transition from an oversupplied market (today) to an undersupplied market (2018 or later), dependent on future wind build.
Midwest	IA, MN, MO	Oversupplied until at least 2020 due to a flood of new wind.
New England	CT, MA, ME, NH	Shortages will continue for the next few years as local wind build sputters and demand centers MA and CT apply stricter rules on biomass generation.
New York	NY	Continue to fall behind on 2015 targets.
Texas	TX	Dramatically oversupplied from cheap wind. Oversupply will deepen due to flat RPS goals.
West US	CO, NM, OR, WA	Broadly oversupplied, with very few pockets of demand for new build.

Source: Bloomberg New Energy Finance. Notes: 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 neighbouring 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, 17 states (plus Washington DC) include 'carve-outs' or special provisions (eg, a renewable energy credit multiplier) for solar or for distributed generation more broadly. This includes most states in the Mid-Atlantic region.

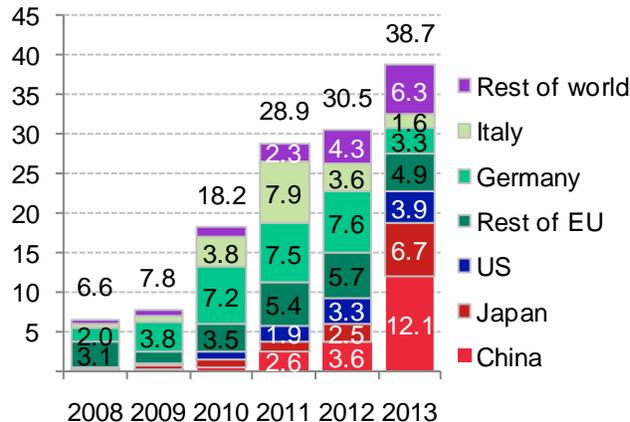
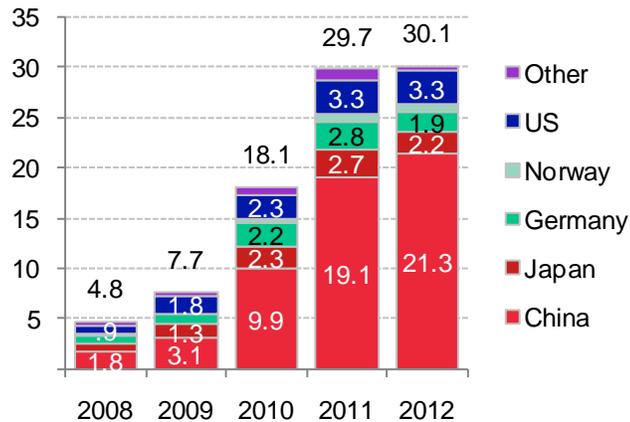
The federal and state governments also support solar build-out through specific technology, financing or procurement programs. These include the now-expired US DOE loan guarantee program: of the \$16.1bn in loan guarantees issued for renewable energy generation and manufacturing, 37% was allocated to concentrated solar power (CSP) projects and 38% to photovoltaic (PV) projects (an additional 8% went to PV manufacturing). A number of these large-scale solar projects have already commissioned, and the remainder are expected to go online in the next few 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 behavior. 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 have faced massive overcapacity in the last few years, but the supply-demand gap is beginning to narrow. There is 63GW of cell and module manufacturing capacity globally, but not all of that capacity is utilized; Bloomberg New Energy Finance estimates that about 40GW was manufactured in 2013 (the 2013 estimates are not shown in Figure 36) to meet global demand for PV modules, estimated to be 36-40GW (Figure 37). US PV manufacturers have faced difficulty competing with foreign panel makers. Domestic module manufacturers' market share fell from 23% in 2009 to 11% in 2012, partly due to price competition from overseas.

Figure 36: Global PV module production by country, 2008-12 **Figure 37: Global PV demand by country, 2008-13 (GW)**



Source: Bloomberg New Energy Finance Note: High-quality data only available through 2012.

Source: Bloomberg New Energy Finance Note: 2013 figures are an estimate, based on a range between 35.8GW and 40.4GW.

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; there were almost 2GW of large-scale PV installations in 2013 (Figure 38). Utility-scale projects made up about half of total PV capacity that came online in 2013; the remaining half was small-scale (covered in Section 5.1). Much of this growth has occurred in California, where solar has become the preferred source of renewable generation for utilities with RPS compliance; just over 1GW of utility-scale PV projects were installed in that state in 2013.

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) and SunEdison's 30MW Webberville plant in Texas (with Austin Energy as the offtaker).

CSP projects were a major beneficiary of the DOE loan guarantee program in 2010 and 2011; the program awarded \$5.1bn to five such projects with a cumulative capacity of 1.3GW. Abengoa's 280MW Solana project was commissioned in 2013, and the remainder are slated to come online in 2014. 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 38: US utility-scale photovoltaic build, 2008-13

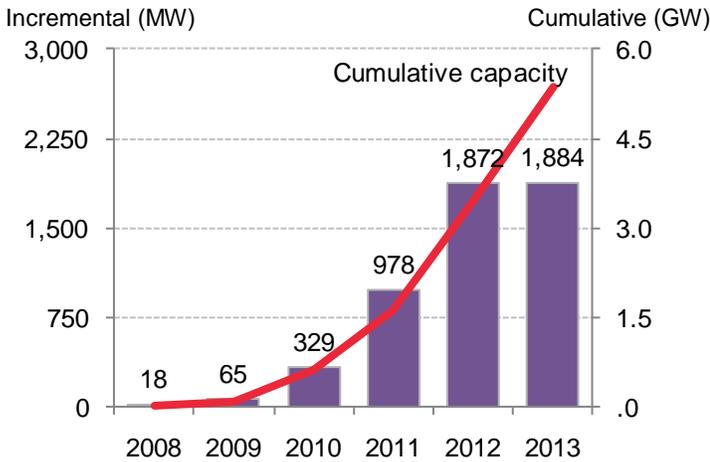
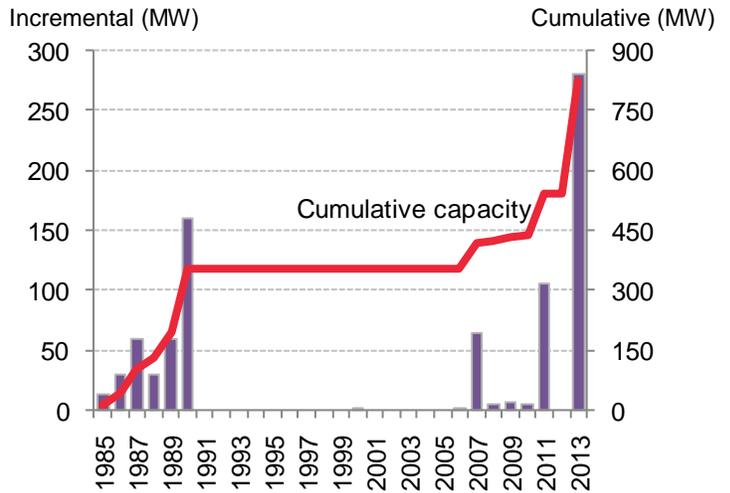


Figure 39: US concentrating solar power build, 1984-2013



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

Venture capital and private equity investment in solar in 2013 was the lowest since 2006, signifying both that the sector is maturing and that developers of the newest technologies are finding it challenging to raise funds. One area that has seen growth is venture capital in the services and support sector, such as third-party financing business models.

Figure 40: Venture capital/private equity investment in US solar by type, 2008-13 (\$bn)

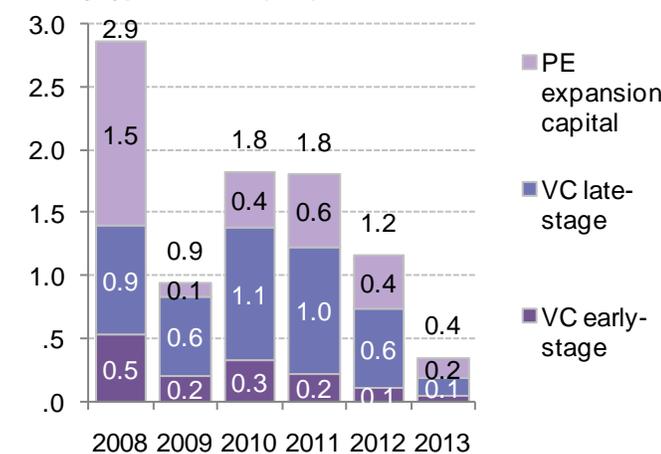
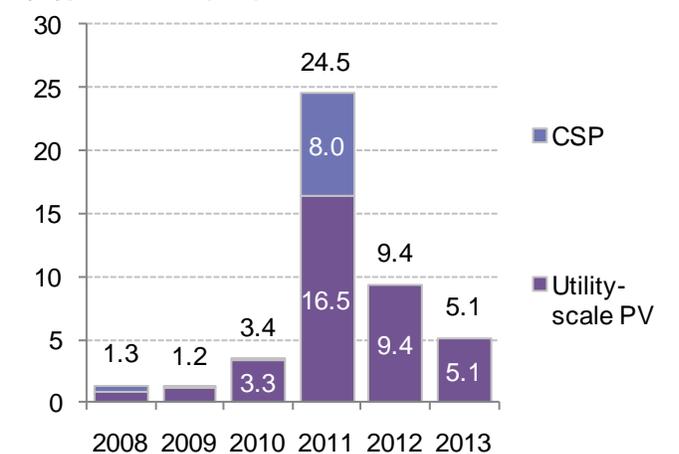


Figure 41: Asset finance for US utility-scale solar projects by type, 2008-13 (\$bn)



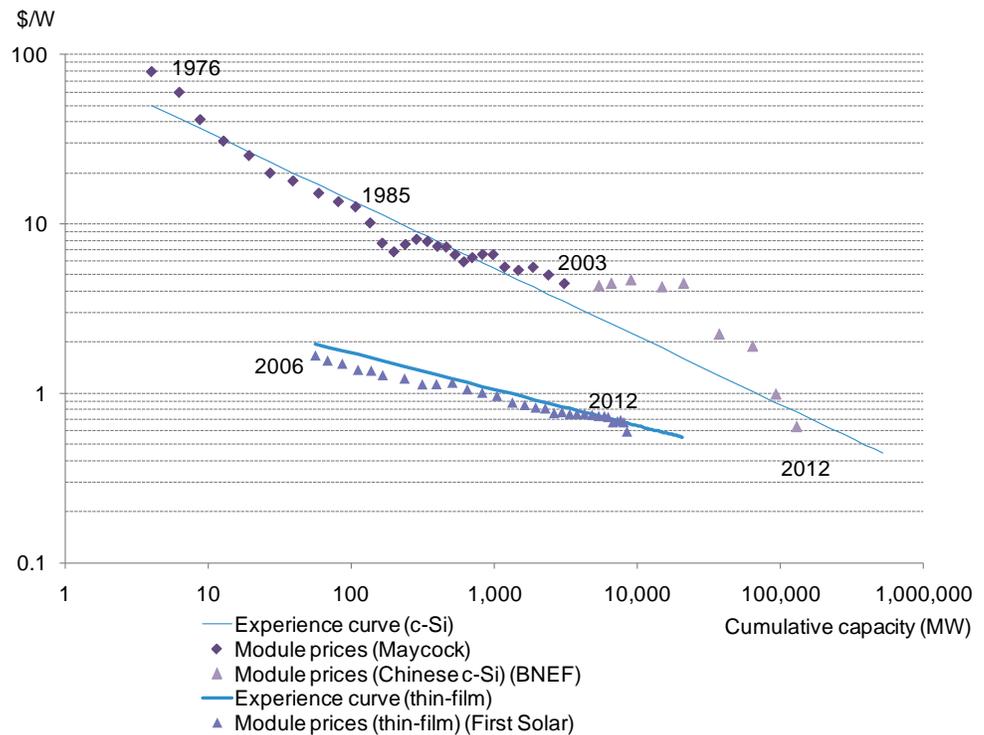
Source: Bloomberg New Energy Finance Note: Values only include electric generating assets and do not include solar thermal water heaters. Values include estimates for undisclosed deals.

In the case of asset financing for utility-scale projects (PV and CSP), investment volumes in 2011 were unusually high, buoyed by the DOE loan guarantee program. Falling investment volumes since can be attributed to reduced demand from utilities needing to meet RPS obligations, the upcoming expiration of the 30% ITC, and – more positively for the sector – the fact that a new solar project requires less investment per megawatt than a solar project just a few years ago, due the rapid decline in equipment costs. Yet while investment volumes in utility-scale solar projects have declined, investments in small-scale solar have soared (discussed in Section 5.1).

Economics

Prices of crystalline silicon modules have fallen 99% since 1976 and by about 80% since 2008 (Figure 42). More recently, oversupply has driven down current global average spot prices to \$0.83/W, but large developers able to obtain discounts are buying panels for \$0.76/W or even lower. 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 42: Capex – price of c-Si PV modules, 1976–2012 (\$/W)



Source: Bloomberg New Energy Finance, Paul Maycock, company filings Note: Prices in 2012 USD.

The module price decline has helped drive down average global best-in-class utility-scale system costs to \$1.55/W (Figure 43). Inverter prices have fallen by nearly two-thirds since 2010, and quotes for engineering, procurement and construction (EPC) for large systems continue to fall as well.

Figure 43: Capex – best-in-class cost of global utility-scale PV, 2010-13 (\$/W)



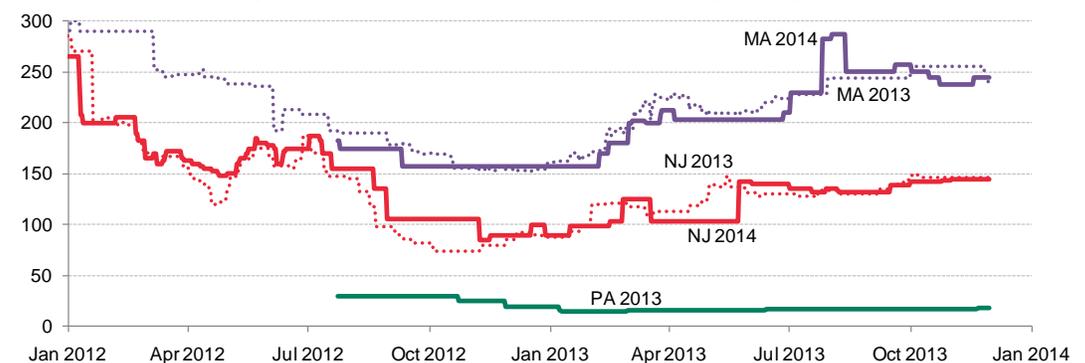
Source: Bloomberg New Energy Finance

Large-scale power projects must contract with off-takers through PPAs for their energy to gain future revenue certainty and achieve bankability. Bloomberg New Energy Finance collected PPA data for 33 utility-scale solar projects located primarily in the desert Southwest, revealing pricing mostly in the \$100–150/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 rates to plummet. Solar PPAs for 2015-16 delivery are now being signed in the mid-to-high \$60/MWh range. One project, First Solar’s 59MW Macho Springs, expected to be commissioned in 2014, signed a PPA for \$57.90/MWh. (It should be noted that this project benefits from New Mexico state tax incentives, which add another \$28/MWh, on average, over the first 10 years of the project.)

Along with cash generated through the sale of electricity through a PPA, solar projects in some parts of the country also generate revenue through 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.

In 2012, SREC prices declined in many markets due to oversupply – ie, more solar power was generated than was required under the targets. In 2013, SREC prices recovered (Figure 44), and developers with low installation costs were able to make the system economics feasible in markets such as New Jersey and Massachusetts.

Figure 44: Solar REC prices in selected states’ markets, 2013 (\$/MWh)



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

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 SunEdison. 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 assets to investors, energy companies, or utilities.

Owners of large-scale renewable energy assets are also benefiting from financing innovations, such as publicly traded investment vehicles and green bonds (Section 8.5).

4.3. Wind

Policy

The major federal subsidy for wind energy in the US is the PTC, which was due to expire at the end of 2012 but which was extended on 1 January 2013 (along with the ITC) for one additional year. The PTC officially expired at the end of 2013 but thanks to an important adjustment to the subsidy it will continue to have market impact through 2015, and to a lesser extent, 2016. Previous versions of the credit required that projects commission by the legislative deadlines, but this latest extension allows projects to qualify as long as they started construction, or incurred 5% of total costs, by the end of 2013. The projects can then be completed at any date provided they are continuously under construction. The incentive provides an income tax credit of roughly \$23/MWh (indexed for inflation) for electricity generation for the first 10 years of the project's life. Other major policy support for wind energy exists at the state level through RPS programs (explained above).

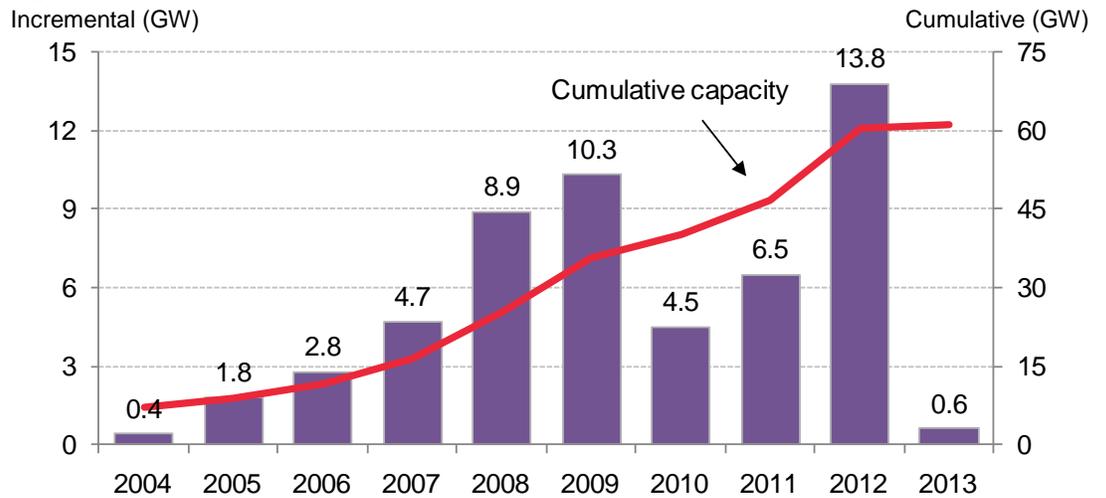
Deployment

2013 was the lowest year for new wind build since 2004 with an estimated 0.6GW in installations (Figure 45). It follows a record year of wind build in 2012 with 13.8GW of new capacity commissioned. The bumper crop of new projects commissioned was largely driven by policy; so was the collapse in 2013. Despite the extension of the PTC in January 2013, the development pipeline for wind had dried up by the end of 2012 in anticipation of the end of federal policy support. (Essentially, in 2011, developers had divided their projects into two categories – those that could be completed by 2012, and those that could not. The latter were shelved, leaving the pipeline for 2013 bare.) In 2012, utilities had also moved forward procurement plans to take advantage of subsidized wind economics.

Despite having officially expired, the PTC should contribute to wind development through 2016. In 2013, over 9GW of PPAs were signed with utilities, with delivery slated from 2013 through 2016. Most of those would have begun construction or incurred costs in 2013 to qualify for the PTC or ITC.⁴

4 Small and distributed wind projects, as well as offshore projects, tend to turn to the ITC rather than the PTC.

Figure 45: US wind build, 2004-13



Source: Bloomberg New Energy Finance Note: Includes all utility-scale wind development, including distributed turbines that are above 1MW (Bloomberg New Energy Finance threshold for utility-scale). Wind build in 2013 was in the range of 0.6-1.1GW; final numbers are not yet available, and the conservative estimate is shown here.

Wind manufacturing capacity on US soil peaked in 2012 (Figure 46). 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. Mitsubishi's facility was mothballed shortly after completion, while Alstom revealed that its facility got off to a slow start. Nordex and Clipper also ceased production in the US in 2013. Other manufacturers, including Gamesa, Acciona, Vestas, and Siemens, announced capacity reductions through workforce lay-offs. Vestas has subsequently re-hired workers to meet new orders (Figure 47).

Figure 46: Wind turbine production capacity in the US by manufacturer, 2008-13 (GW)

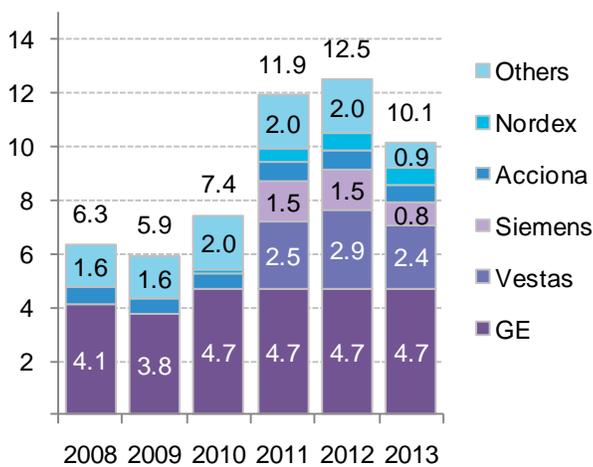
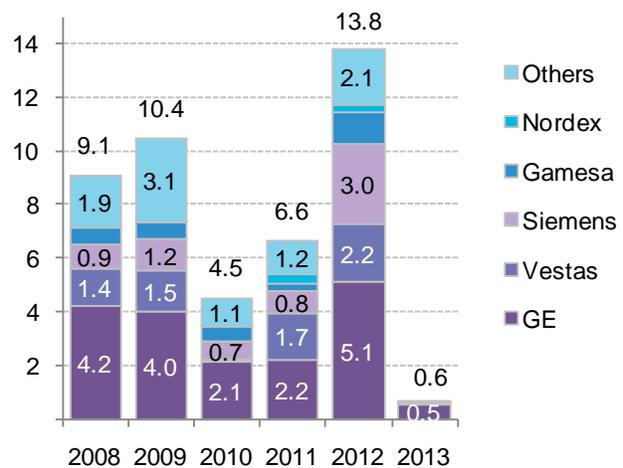


Figure 47: Wind turbine supply contracts for commissioned US projects by commissioning year, by manufacturer, 2008-13 (GW)

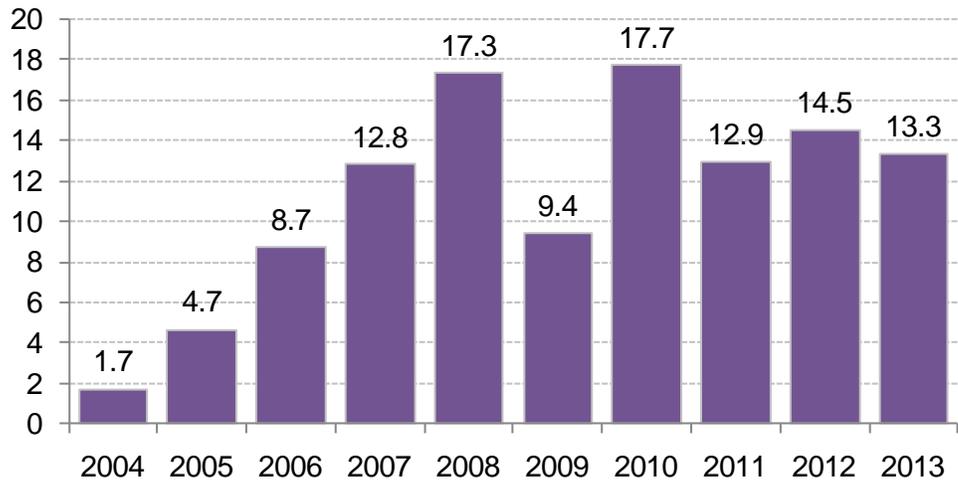


Source: Bloomberg New Energy Finance Note: Wind build in 2013 was in the range of 0.6-1.1GW; final numbers are not yet available, and the conservative estimate is shown here.

Financing

Asset (project) finance volume in 2013 for new wind projects totalled \$13.3bn (Figure 48). Wind received only \$2.6bn in asset finance in the first three quarters of 2013. Announced asset financings picked up significantly in Q4 2013 as projects that have secured long-term PPAs received financing and started construction to take advantage of the PTC.

Figure 48: Asset finance for US wind projects, 2004-13 (\$bn)

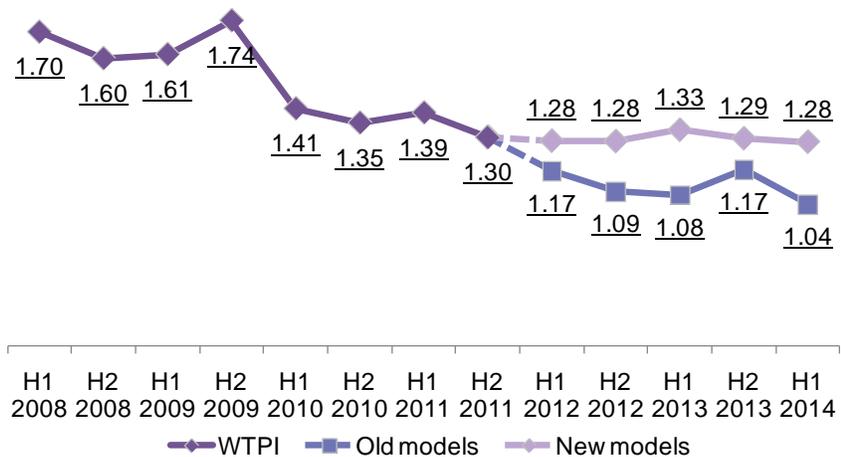


Source: Bloomberg New Energy Finance Note: Values include estimates for undisclosed deals.

Economics

Global turbine prices declined by roughly 35% over 2009-13 (Figure 49). Keeping all other cost components equal, this decline in turbine prices equates to a 23% decline in the levelized cost of electricity (LCOE) for wind. Turbine performance has also improved, particularly for those purposed for low wind speeds; this effectively improves the capacity factor, further lowering the LCOE.

Figure 49: Capex – wind turbine price index by turbine type and delivery date, 2008-14 (\$m/MW)



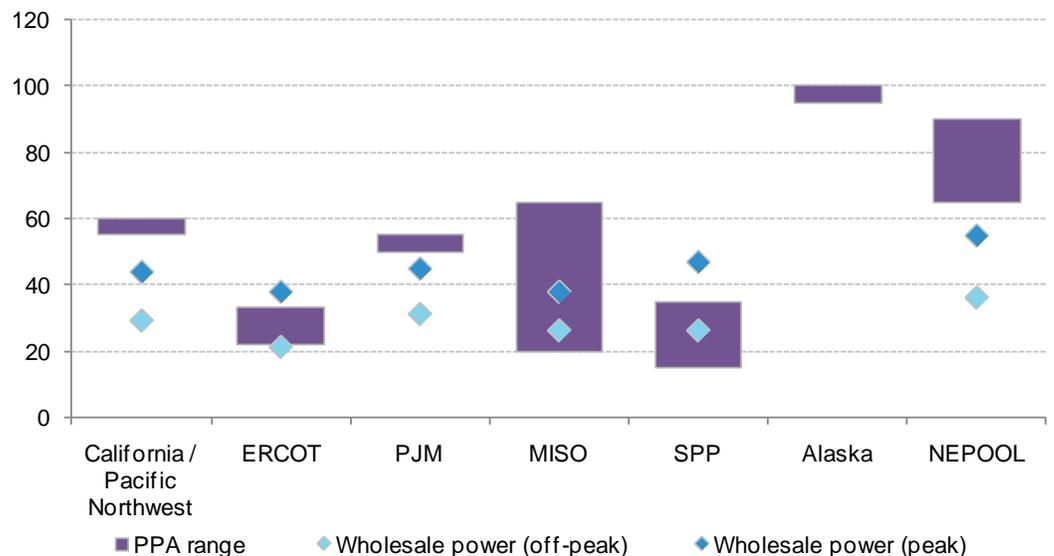
Source: Bloomberg New Energy Finance Notes: Global Wind Turbine Price Index converted from EUR to USD by the average EUR/USD rate for the half year of turbine delivery. The 35% decline cited above refers to the drop

from \$1.74m/MW in H2 2009 to \$1.13m/MW in H2 2013; the \$1.13m/MW is the average between the H1 2013 and H2 2013 numbers, and is a better benchmark than the \$1.17m/MW value, which may be an anomaly.

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 high forties in 2013. In Texas, MISO and SPP, PPA prices in 2013 were recorded in the \$20-35/MWh range, and at least one contract was rumored to be \$15/MWh though with a planned but undisclosed "escalator" in the price in future years (Figure 50). These prices were contingent on the PTC. Without a federal subsidy, pricing on these contracts would likely have been in the mid-forties to mid-sixties.

The benefits of these economics can flow to consumers. In December 2013, DTE Energy, a Michigan utility, announced that it would be lowering customers' electricity rates by 6.5% in 2014, citing low-cost wind as one of the major factors.

Figure 50: PPA prices for select US wind markets (\$/MWh)

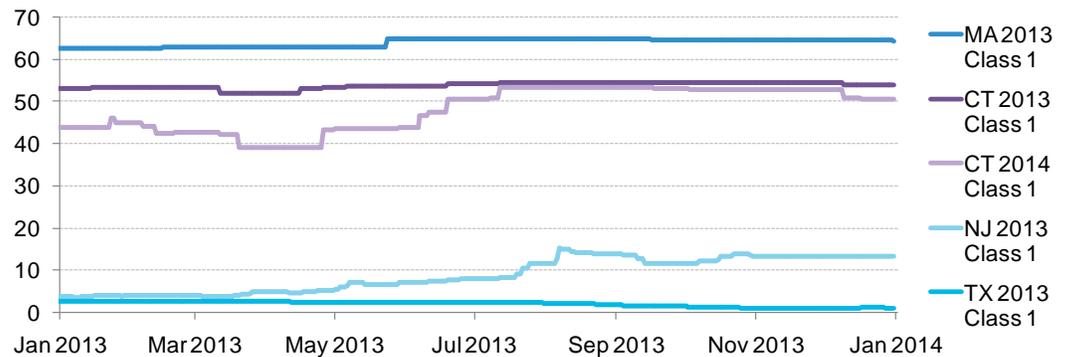


Source: Bloomberg New Energy Finance, Federal Energy Regulatory Commission, SEC filings, analyst estimates
 Notes: 'ERCOT' refers to Texas; 'PJM' refers to the Mid-Atlantic market; 'MISO' refers to the Midwest; and 'SPP' is the Southwest Power Pool, covering the central southern US. Ranges for PJM and California / Pacific Northwest are relatively slim due to limited amount of disclosed data.

Due to lower-priced PPAs, some utilities signed contracts allowing them to procure more renewable power than required under their state's RPS targets. This in turn caused REC prices to collapse in key markets such as Texas (Figure 51). In contrast, New England's REC market remains tight – and credit prices are high – as difficulties with project permitting make it burdensome for new supply to enter the market.

One region has bucked both these trends. In PJM, which encompasses mid-Atlantic states and some in the Midwest including parts of Illinois and Indiana, REC prices rose gradually over the course of 2013. Though there is plenty of generation, and 'banked' credits, to meet near-term RPS targets in that region, the rise in prices could reflect the expectation that the market will shift from oversupply to undersupply later in the decade (and higher REC prices will thus be required to make project economics viable and bring more capacity online).

Figure 51: 'Class I' REC prices in selected markets, 2013 (\$/MWh)



Source: Bloomberg New Energy Finance, Evolution, Spectron Group Notes: '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 as of year-end 2013 included NextEra, Iberdrola, MidAmerican Energy, and EDP (Figure 52). Though nearly all of the top 10 US wind owners are utilities, only MidAmerican is building the majority of its capacity for its own consumption. All others listed in Figure 52 are building wind projects as independent power companies selling to other utilities. A small percentage of annual wind build is owned and operated by regulated utilities and used for their own consumers (Figure 53).

Figure 52: Top 10 US wind owners, as of end-2013 (MW)

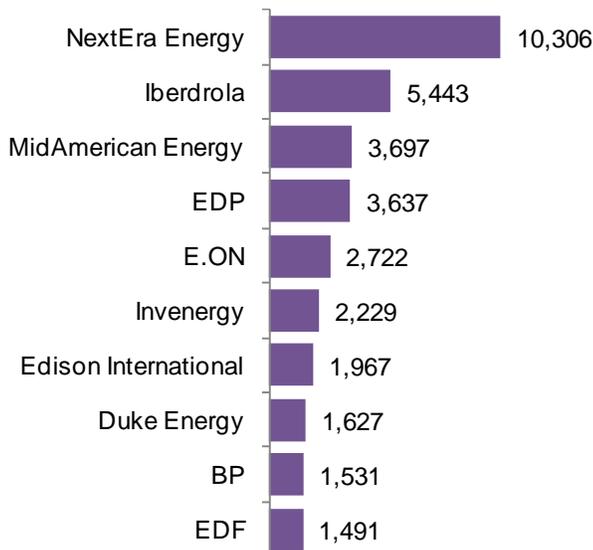
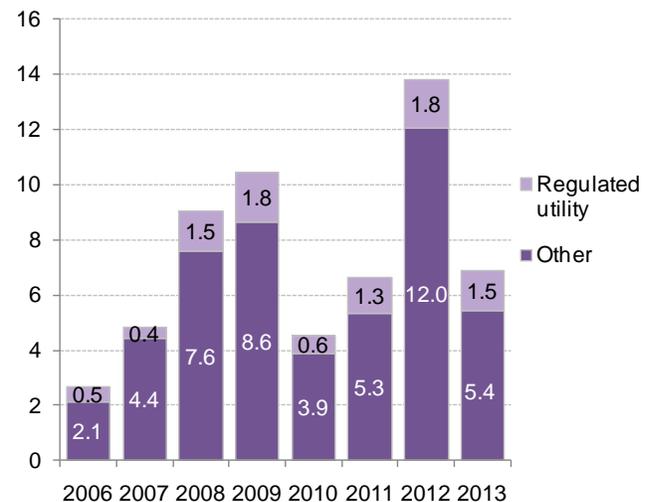


Figure 53: US wind capacity commissioned or under construction by type of developer, 2006-13 (MW)



Source: Bloomberg New Energy Finance Notes: In Figure 52, 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. Analysis does not account for NRG Energy's acquisition of Edison International's subsidiary Edison Mission's assets, a transaction that was announced on October 2013 but was not yet finalized as of January 2014. In Figure 53, 'Regulated utility' refers to projects owned and developed by utilities for their own customers. 'Other' includes projects built by non-utilities such as independent power producers and also includes projects built by the non-regulated development arms of utilities such as Duke or NextEra; in those cases, the projects are not supplying power to the regulated utilities' ratepayers but rather to a third party.

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 and then sell them to larger developers or asset owners for final construction. Proceeds from the sale of equity in commissioned or close-to-commissioned projects are reinvested in other development assets.

4.4. Biomass, biogas, and waste-to-energy

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 provides a critical incentive in the form of the PTC, valued at \$11/MWh. The credit was available to projects operating or under construction by the end of 2013, for electricity derived from biomass and waste.

While mandated demand is the main driver behind the development of biomass-to-power facilities, waste-to-energy is often employed by communities on the merits of being a more sustainable waste management solution than landfilling of waste – with the added benefits of renewable power production, greenhouse gas reduction, improved local recycling rates, and preservation of land.

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 three years. The US Department of Agriculture's Biomass Crop Assistance Program (BCAP), which offers direct subsidies for new energy crops, dwindled in 2012 and waned in 2013 after the 'fiscal cliff' deal did not include any mandatory funding for it. The 2014 Farm Bill – in its current House-approved form – revives BCAP. In the new bill \$25m per year of mandatory funding for 2014-18 is being proposed. Further downstream, the expiration of the PTC in 2013 is dealing a strong blow to the sector; deployment surged to take advantage of the expiring credit, and investment sank with the expectation that future projects would not be able to count on this incentive.⁵

Biogas

Biogas produced in wastewater treatment facilities, landfill gas power projects, and digesters for manure and other organic residues is a key contributor to the production of renewable electricity in the US. A large number of existing landfill gas power projects benefits from the PTC and from states' RPS. In the case of the production of renewable transportation fuels, some even benefit from the federal Renewable Fuel Standard (RFS2). These types of incentive are critical to the financial success of most biogas projects.

5 Although the legislation stipulates that projects must merely begin construction, rather than achieve commissioning, by year-end 2013, it takes time for developers to replenish the pipeline for investments. Furthermore, despite the legislation's accommodating language, investors may have been put off from financing new projects due to concern about meeting future deadlines. Specifically, in September 2013, the IRS issued guidance explaining that projects will be deemed to have met the criteria for tax credit eligibility so long as they commission before 1 January 2016. Biomass plants often have long lead times and can face high risk of project delays, raising concern that they would miss that cut-off date.

Waste-to-energy

The Energy Policy Act (2005) and Energy Independence and Security Act (2007) were important policy developments for the industry as they all reconfirmed the renewable status of waste-to-energy. Inclusion of waste-to-energy in many state RPS programs offers further encouragement to the industry.

Since 2004, waste-to-energy technologies have been eligible to claim the PTC. Yet the construction of new waste-to-energy facilities is associated with very long periods (up to a few years) of planning and permitting process. This timeline, coupled with the sporadic short-term extensions of incentives over the last several years, has made it difficult for the waste-to-energy industry to capitalize on the incentives, compared to other technologies with shorter development timelines.

At the state level, 31 states and two territories have explicitly defined waste-to-energy as an eligible renewable energy technology under various regulations.

Deployment

Biomass

Since 2008, interest in dedicated biomass combustion picked up, driven by a combination of attractive state subsidies, feedstock availability, and the PTC incentive. In 2013, some 230MW of additional biomass-to-power capacity was commissioned, making this year the most successful in terms of new capacity since 2009 (Figure 54).

Biogas

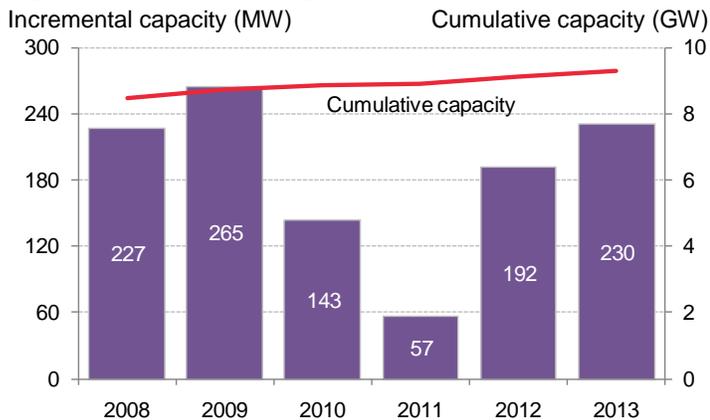
Landfill gas can be used for power or can be put to direct use (ie, renewable natural gas, or biomethane). There were only three known new projects built in 2013, summing to 9MW, but each of the five years prior saw 94-163MW of new build. There are currently 782 operational landfill gas power projects in the US, with a combined capacity of 1,835MW of renewable electricity and 8.4m m³/day of biomethane for direct use, according to the EPA Landfill Methane Outreach Program (LMOP). Currently, there are 34 farm-based utility-scale (ie, >1MW) anaerobic digestion plants operating in the US. On average, 7MW of new utility-scale anaerobic digestion capacity have been added every year since 2005, with the average size of these projects currently around 1.5MW.

Waste-to-energy

In 2011, merely 7.6% of US MSW supply was processed at waste-to-energy facilities.⁶ (For comparison, the average rate of energy recovery from waste in Europe is approximately 40%.) The number of waste-to-energy plants in the US has fallen from roughly 180 facilities in the 1980s to 84 currently. Tax law changes, new landfill site development, low gate fees (the fees that an MSW facility charges to receive waste), and the introduction of Maximum Achievable Control Technology (MACT) standards have caused considerable industry disruptions. The majority of waste-to-energy facilities are located in the northeast US, where the landfill gate fees are the highest and surpass the waste-to-energy gate fees. Most development occurring today is not greenfield; in 2011, the 6MW of new capacity additions were expansions of existing waste-to-energy projects.

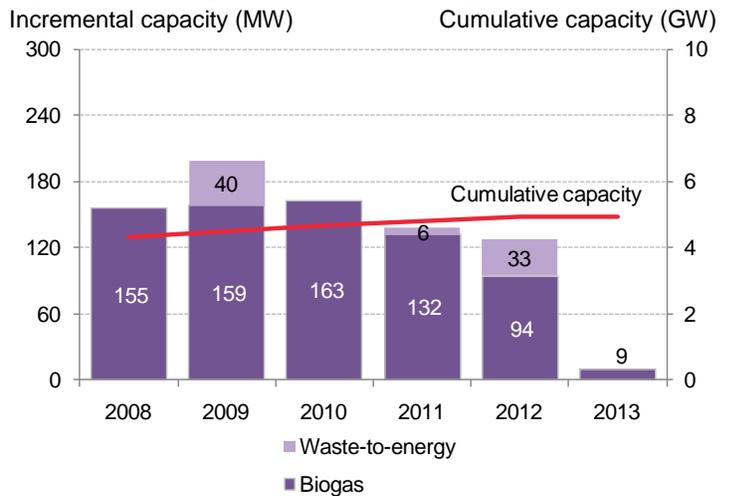
6 According to Columbia University Earth Engineering Center, MSW disposition study, 2013 (using 2011 data)

Figure 54: US biomass-to-power build, 2008–13



Source: Bloomberg New Energy Finance

Figure 55: US biogas and waste-to-energy build, 2008–13



Source: Bloomberg New Energy Finance Notes: Biogas category includes anaerobic digestion (projects 1MW and above except wastewater treatment facilities) and landfill gas power.

Financing

Biomass

Between 2010 and 2013, some \$4.1bn was invested in the US biomass sector, but the 2013 amount (\$118m) was the lowest in a decade (Figure 56). PTC expiration is at least partly to blame for the poor performance. Biomass projects seeking capital typically need a signed PPA, an experienced EPC contractor, and some protection against the risks associated with feedstock availability and prices.

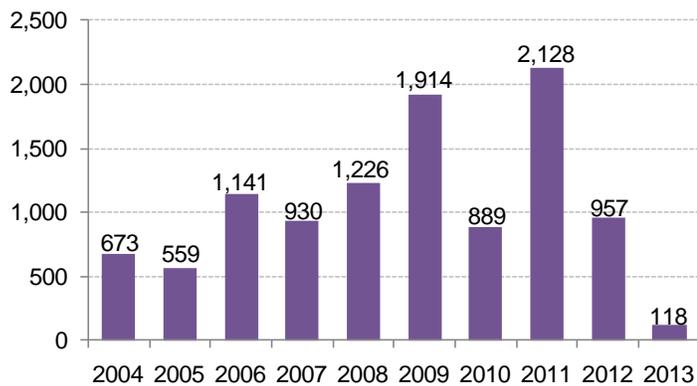
Biogas

Since 2008, Bloomberg New Energy Finance has recorded roughly 50 asset finance deals in biogas. From 2004 to 2013, some \$1.8bn was invested in the biogas market, with an average of \$180m committed per year. Over 70% of the committed funds came from landfill gas power transactions with most of the rest going toward anaerobic digestion. The biogas sector in the US saw its record high in 2007, when some \$370m was invested in the build-out of landfill gas power and anaerobic digestion capacities.

Waste-to-energy

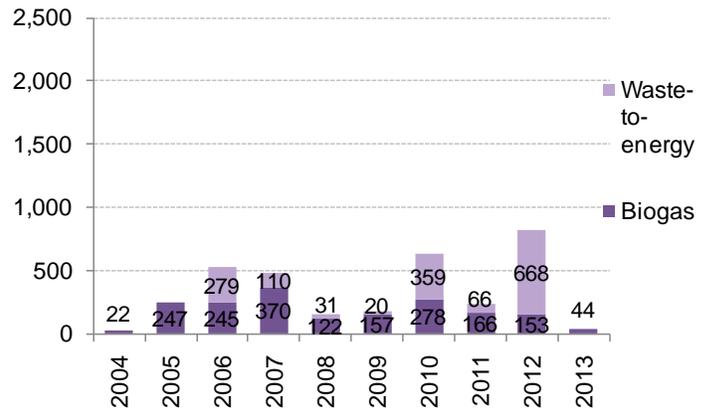
The US waste-to-energy sector is small and investment opportunities are scarce. Since 2006, Bloomberg New Energy Finance has recorded just 13 such asset finance deals and not one was recorded in 2013. US asset finance investment in waste-to-energy is very patchy and not very balanced, with single deals contributing meaningfully to annual totals. The sector saw its record investment in 2012, when over \$660m was secured for one project: a 95MW waste-to-energy plant in West Palm Beach developed by the Palm Beach County Solid Waste Authority (SWA).

Figure 56: Asset finance for US biomass, 2004-13 (\$m)



Source: Bloomberg New Energy Finance Note: Includes expansion deals

Figure 57: Asset finance for US biogas and waste-to-energy, 2004-13 (\$m)



Source: Bloomberg New Energy Finance Note: Includes expansion deals

Economics

Biomass

Project economics are driven by capex, which decreases (on a \$/MW basis) with scale, and by feedstock costs, which tend to rise with scale (as it becomes more difficult to source larger volumes).

Capex for biomass combustion varies depending on project size, and depending on whether the project is a new facility or a retrofit. Figure 58 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-fired 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 costs, the US feedstock supply industry has profited from a boom in wood pellet demand. Demand was mainly spurred by subsidies in some European countries that support the conversion of old coal plants to biomass-to-power plants. Exports to Europe of local wood pellets, a premium feedstock with controlled fuel value, reached 2.8m tonnes in 2013, an increase of almost 60% compared to 2012. With an average delivered price of \$172/tonne⁷, the trade is worth nearly half a billion dollars.

Biogas

Capex for biogas technologies is relatively stable at roughly \$3.5m/MW for anaerobic digestion and \$3m/MW for landfill gas power projects. Scale of the project has a negligible effect on average capex figures. With both technologies being quite established, there are little historic changes in costs.

Landfill gas power projects benefit from received gate fees which constitute another source of revenue, next to sales of electricity and RECs. Moreover, anaerobic digestion projects can count on

7 This price differs from the prices shown in Figure 58. This is due to several reasons: the 'delivered price' includes other costs, such as pelletization and transport; pelletized wood pellets have higher fuel value compared to untreated wood; and wood pellets not often the feedstock used for US biomass.

revenues from sales of a digestate – a by-product of anaerobic digestion that can be marketed as a soil enhancer.

Waste-to-energy

Capex for waste-to-energy varies considerably depending on deployed technology, location and size of the plant as well as the type of sorting and recycling facilities that tend to be built at new waste-to-energy facilities.

As in the case of landfill gas power projects, project economics of waste-to-energy plants are also impacted by revenues from gate fees (as well as sales of electricity, heat, and RECs). In general, gate fees for waste-to-energy are higher than for landfilling. The average waste-to-energy gate fee in the US is about \$68/tonne, almost 50% higher than the average landfill gate fees (\$45/tonne).⁸ This is not conducive to the development of more combustion plants as the penalty for combusting a tonne of MSW is greater. This helps explain why the rate of new build has been falling drastically.

Figure 58: Biomass feedstock prices in selected US markets, 2011–13 (\$/dry tonne)

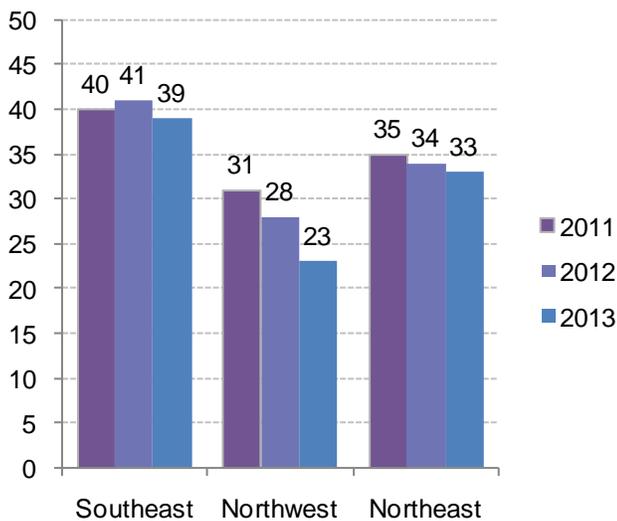
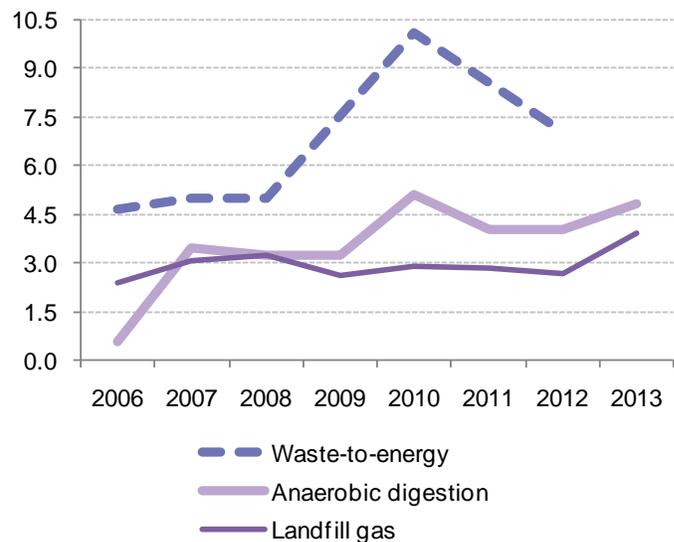


Figure 59: Capex – capital costs for biogas and waste-to-energy projects by type, 2007-12 (\$m/MW)



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

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 LCOE. 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?

While many existing plants are sheltered from the price effects of the shale gas boom through long-term PPAs, those whose contracts expire or which seek new arrangements have faced an uphill

⁸ US average landfill gate fees are less than half the average landfill gate fee in Europe (\$110/tonne). While European landfill gate fees have been increasing as a result of the EU-wide legislation that is aimed at drastically reducing the number of operating landfill sites, introduction of similar legislation is unlikely in the US in the short term. However, as many states run out of landfill capacity, gate fees could increase slightly.

battle. Without further support, some plants in New England might soon face the decision of whether to run exclusively during times of seasonal peak demand or to stop operating altogether.

Meanwhile, wood pellets for export to Europe have become a small but very high-growth market that is starting to catch the attention of mainstream investors. The southeast US in particular has seen a boom, with 4.8m tonnes of production capacity commissioned already and another 7m tonnes proposed. Investors are beginning to get comfortable with the specific risk profile of this budding industry, which links North American wood fiber markets with European energy policy.

Biogas

While the number of landfills in the US has been steadily decreasing since 1988, the average landfill size increased. In 2010 over half of MSW was deposited on a landfill site, and in 2011 landfills contributed to 17.5% of total US emissions of methane. Landfill gas power technology has become successfully promoted as a cost-effective and environmentally beneficial way to reduce methane emissions. As a result, landfill methane emissions in the US have decreased 30% since 1990 and the number of landfill gas power projects grew from roughly 150 in 1995 to 782 today.

Waste Management is among the largest players, with over 180 landfill gas operations and a combined 510MW of electricity capacity; another is Republic Services, with over 90 projects and 240MW of electricity capacity.

Landfill gas projects represent the majority of generating capacity, as low natural gas prices were not conducive to the increase in direct use of produced biogas. However, an opportunity has begun to open up in the transport sector, where upgraded biogas is gaining in importance as a substitute for compressed natural gas (CNG) and LNG (Section 7.2). The growing role for biogas in transport has been enabled by the Renewable Fuel Standard (RFS2) policy.

Waste-to-energy

There are several key barriers obstructing more investment for US waste-to-energy: the absence of strong legislation to encourage waste-to-energy expansion; low landfill gate fees; low or variable energy prices; and challenges with siting of waste management facilities. It has historically therefore been difficult for waste-to-energy technologies to compete with landfill sites, resulting in landfilling rates above 50%.⁹ However, some 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.

Covanta and Wheelabrator (a subsidiary of Waste Management) are among the most significant players in the US waste-to-energy industry. Covanta operates 40 waste-to-energy facilities in the US, totaling around 1.5GW nameplate capacity, and processes around 20m tons of MSW annually. Wheelabrator operates 17 plants that have a combined capacity of 670MW and process 9m tons of MSW annually. Covanta and Wheelabrator operate more than 60% of all the US waste-to-energy facilities.

9 For comparison, China currently landfills roughly 80% of its MSW and the UK more than 50%. However, both China and the UK have in the last few years made great efforts to improve their waste management sector (eg, waste-to-energy feed-in tariffs and waste-to-energy targets in China, Landfill Tax Accelerator in the UK), and both countries are on their way to increasing their waste-to-energy capacity. In addition, most of the old EU member states already make a productive use of their waste and see MSW as an important energy feedstock.

4.5. Geothermal

Policy

Geothermal projects have long development timelines of 4-7 years, making the stop-start nature of federal renewable energy policy particularly troublesome for developers. Most recently, the \$23/MWh PTC expired at the end of 2013 (developers also had the option to receive a 30% ITC in lieu of the PTC). However, as with other technologies, projects were required to only be under construction by end-2013 to be eligible for the incentive. Several projects qualified and are currently under development. Notably, for geothermal, the criteria for 'under construction' can be met by drilling production wells.

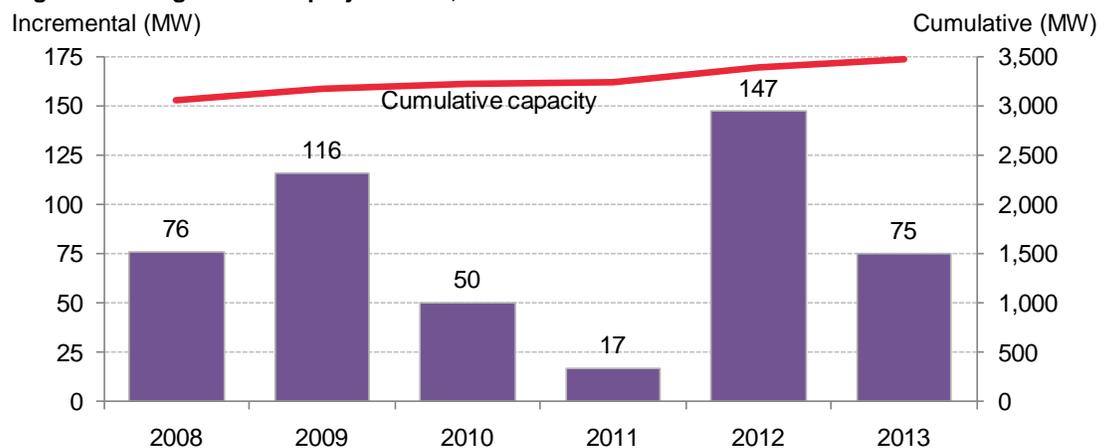
Currently, new greenfield projects are only eligible for a 10% ITC, which has no expiration date. Geothermal has also benefited from state RPS programs – particularly in California and Nevada. On the state level, bills currently in the state legislatures of both California and Nevada could, if passed, require utilities to place additional value on the baseload generation profile and reliability attributes of geothermal energy relative to variable renewables.

Deployment

The US has more installed geothermal capacity than any other country, but geothermal represents just a slim part of domestic renewable energy generation and a tiny slice of the overall US energy portfolio. There is currently just under 3.5GW of installed geothermal capacity (Figure 60), and installed capacity has grown by a compound growth rate of just over 2% since 2008.

The US Geological Survey estimates that US geothermal resource potential, including existing and undiscovered resources, is between 12GW and 90GW. However, many known sites are not being developed because of inaccessibility. Many geothermal resources are located on undevelopable land, areas without accessible transmission or in protected areas. The Salton Sea in southern California is one area with significant remaining geothermal resources and available transmission capacity, and in 2013 the Imperial Irrigation District announced that it would focus on supporting up to 1,700MW of new geothermal in the Salton Sea area.

Figure 60: US geothermal project build, 2008-13



Source: Bloomberg New Energy Finance

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, East Africa, Chile, and Central America. In some developing markets, resource strength, high electricity prices and policy can help developers overcome drilling risk and other challenges.

The 2009 stimulus helped bring five plants with a cumulative capacity of 147MW online in 2012, the highest since 1990. Developers built another four projects totaling 75MW in 2013.

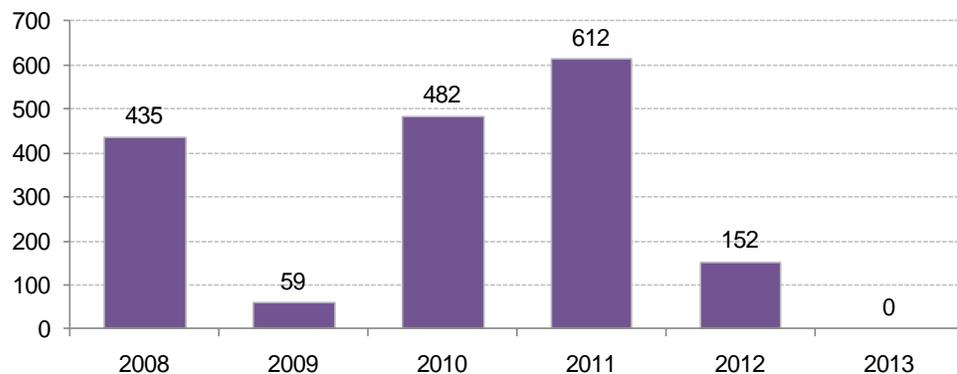
Geothermal development is risky and lengthy. Geothermal technology has also not seen the same cost reductions or performance improvements witnessed in the solar and wind sectors. As a result, geothermal energy is often more expensive for utilities than solar or wind (see below). While the 2013 edition of this report noted that the Hawaii Electric Light Company was seeking 50MW of geothermal, in December 2013 the utility stated that no bidders were able to meet the "low-cost and technical requirements of the Geothermal RFP". But, it has granted bidders additional time to respond.

Many 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 or to place additional value on baseload renewable generation.

Financing

Geothermal developers did not close on any asset finance transactions in 2013. This is a function of both the limited size of the US geothermal market and the stop-start nature of federal incentives. That is, projects that might benefit from the 2013 extension of the PTC have not yet sought project finance.

Figure 61: Asset finance for US geothermal projects, 2008-13 (\$m)



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

In the past few years, vendor financing has emerged as an alternative to traditional sources of capital: developers receive financing at favorable 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 (120-180°C) geothermal fluid to

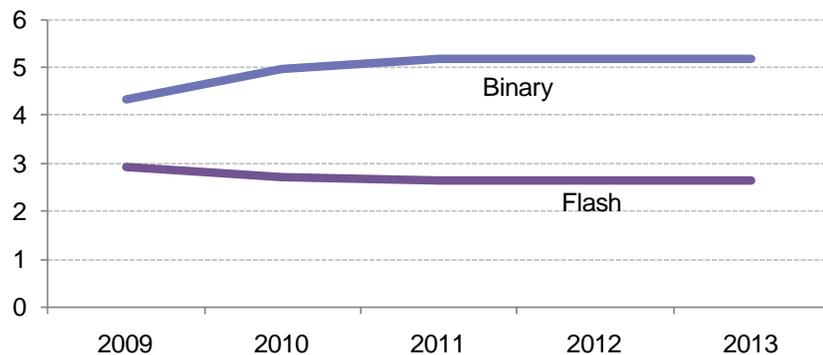
heat a secondary 'working fluid' with a lower boil point; this secondary fluid turns to steam and drives a turbine. Projects can operate using even lower-temperature fluid, although not at MW-scale sizes.

Project capex can vary significantly depending on site-specific characteristics. Large flash projects are usually – but not always – cheaper than binary projects. On a global basis, capex averaged about \$2.65m/MW for flash and \$5.18m/MW for binary projects over 2011-13. In the US, flash project capex has been higher in recent years (one project was built in 2012 at \$8m/MW), but this may be due more to the specifics of the sites where flash projects are built, rather than due to the technology being fundamentally more expensive.

Averaging \$63-97/MWh, the LCOE for geothermal is often near the lower end of the spectrum when compared to other renewable technologies. But the high upfront cost and risk of exploratory drilling often keeps projects stranded at the starting line. Additionally, as 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 favorable. 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 62: Capex – capital costs for geothermal projects by type, 2008-13 (\$m/MW)



Source: Bloomberg New Energy Finance

In 2013, three geothermal PPAs closed in the range of \$85-100/MWh. For comparison, solar PPAs at the same time were closed at less than \$70/MWh, and wind contracts were signed in the range of \$20-35/MWh.

Market dynamics

While several projects qualified for the PTC in 2013, there has been relatively little greenfield development. Developers are facing reduced federal incentives, limited demand for new geothermal PPAs, and decreasing cost-competitiveness on a \$/MWh basis versus other forms of renewable energy. At the same time, state legislation benefiting geothermal in California and Nevada could open up new doors, and increased interest in the Salton Sea geothermal area offers positive signs. While several developers are maintaining a presence in the US market (eg. Ormat Technologies, Enel Green Power, EnergySource and Gradient Resources), others are eyeing international markets.

Ormat Technologies is one of the best-capitalized and experienced players in the US geothermal market, and may continue to be the most prolific developer.

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).

In 2013, President Obama signed two new hydropower bills into law – the Hydropower Regulatory Efficiency Act of 2013 and the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act – both of which passed Congress with overwhelming bipartisan support. The laws seek to expedite the licensing of certain types of hydropower projects, including small and conduit projects, closed-loop pumped storage and the addition of hydropower generation the nation's existing non-powered dams.

Prior to passage of the Regulatory Efficiency Act, projects under 5MW could seek exemptions from the Federal Energy Regulatory Commission (FERC) licensing. The Act increased this level to 10MW, allowed developers to seek exemptions on conduit¹⁰ hydropower projects up to 40MW, and required FERC to investigate a two-year licensing process for development at non-powered dams and closed-loop pumped storage facilities. The Bureau of Reclamation Act requires the Bureau to contract out its conduit facilities for private hydropower development under 5MW.

While small, these legislative developments may represent stepping stones toward a more ambitious goal of accessing larger unpowered dams for new generation. It is estimated that the top 100 non-power dams could add 8GW of new hydropower capacity if all were to be converted; 81 of these are controlled by the US Army Corps of Engineers.

Deployment

At 7% of total generation, hydropower is the second-largest largest source of non-fossil-fuel power in the US. Hydropower has a large installed capacity base of 79GW, or 101GW including contributions from pumped storage projects. But development in recent years was limited until 2011 after Congress allowed the technology to benefit from the 1603 Treasury 'cash grant' program. The industry saw 345MW commissioned in 2012, a 15-fold increase over 2010 (Figure 63).

Development in recent years has been mainly plants below 100MW. Yet there is some activity to pursue larger 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 commissioned its 125MW expansion of the 108MW Holtwood plant in December 2013, confirming its eligibility for the cash grant, equal to 30% of the \$443m cost (hydropower facilities needed to commission by end-2013 to realize the cash grant).

Though recent installation numbers have been low, developers have received licenses or exemptions from FERC for 610MW of new capacity since 2009, potentially foreshadowing an upswing of new development (Figure 64). (Exempted projects do not require renewed applications to FERC to

¹⁰ Conduits are defined in the act as "a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance."

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 63: US hydropower project build, 2009-13

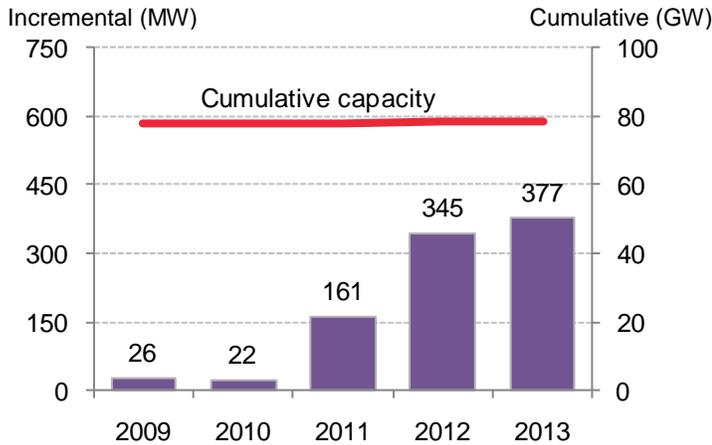
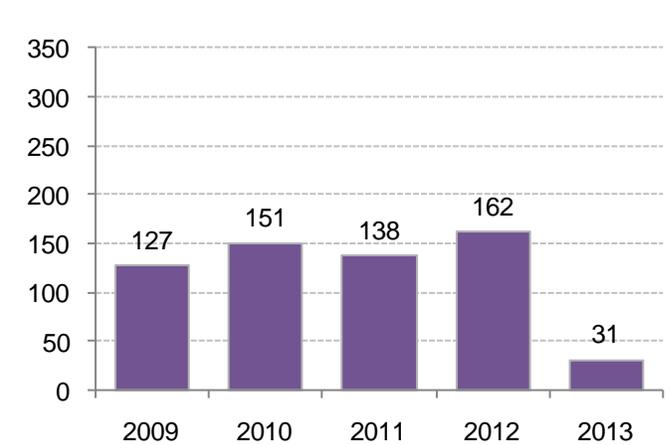


Figure 64: US new hydropower capacity licensed or exempted by FERC, 2009-13 (MW)



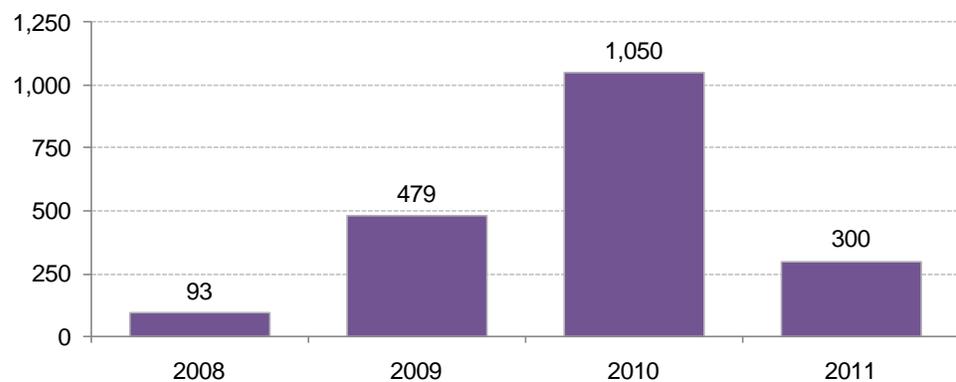
Source: Bloomberg New Energy Finance, EIA, FERC Note: Data on cumulative capacity are from the EIA; incremental capacity from FERC. The 2012 licensing figure excludes 152MW of pumped storage licensed in 2012 (this had been included on the chart for last year's report).

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 totaling 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 off-taker.

Figure 65: Annual asset finance for US hydropower projects, 2008-11 (\$m)



Source: Bloomberg New Energy Finance Note: 2012-13 data are 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

State-owned bodies are the largest hydro owners in the US. The US Army Corps of Engineers holds 21GW and the Department of Interior's Bureau of Reclamation owns 14GW. In the world of small hydropower, the largest asset owner is the publicly-traded Brookfield Renewable Energy Partners. As of end-2013, the company had 112 US projects in 10 states totaling 2,814MW 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 (IPPs) 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 capex 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

Distributed generation has a modest presence in the US power sector, but that is rapidly changing. Financiers that back small-scale solar systems have raised nearly \$7bn since 2008. Fuel cells installations saw their strongest year yet in 2013, and installations of CHP generation in 2012 topped the levels of the previous four years. Distributed generation's rise is ushering into US power new players and new business models, while testing the durability of traditional practices. The potential stakes are high as evidenced by the intense regulatory battles that played out across the country in 2013 over the relative costs and benefits of distributed PV.

Meanwhile, other new technologies with transformative potential for the grid – including storage technologies other than pumped hydropower and CCS – are beginning to show promise, in some cases for the first time.

5.1. Small-scale solar

Policy

Solar carve-outs under RPS programs serve as a source of demand for small-scale solar. In fact, in some states in the West, small-scale solar benefits from carve-outs unavailable to larger projects. Arizona and Colorado have distributed generation carve-outs along with New Mexico, which also has its 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.

Net energy metering issues, including the value of the credit and the amount of net metering that can be allowed in an area – along with the broader question around the relative costs and benefits of small-scale solar – have become the subjects of at times fierce debate in various US states. Solar advocates have pushed for higher net metering caps and for net metering compensation that recognizes the full range of benefits offered by on-site solar, including avoided emissions and lower losses associated with transmission. Opponents argue that owners of solar systems should pay fixed fees or be compensated at lower rates for sales of their excess electricity into the grid, claiming that doing so otherwise unfairly burdens those without systems, and have sought to rein in the amount of net-metered capacity, citing concerns about technical limitations on the grid.

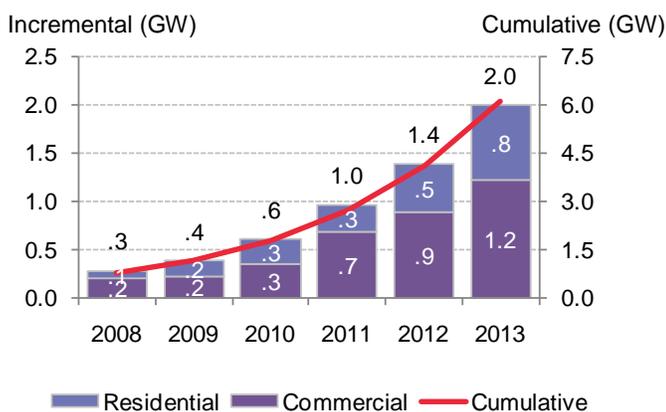
California and Arizona, the country's two largest markets, were among the states that contended with these politics in 2013. In California, the passing of bill AB 327 in September, which extends net metering until 2017, bolsters the prospects for distributed solar, but also opens the door to new electricity pricing structures which make residential solar less competitive. In Arizona, regulators granted Arizona Public Service (APS) the power to impose a \$0.70/kW monthly charge on new solar customers, the first utility fee on residential PV. The California decision was widely perceived as a compromise; the Arizona decision as a narrow win for the solar industry, since APS had been seeking a much higher fixed fee.

Deployment

Small-scale solar grew from cumulative installed capacity of 0.6GW as of 2008 to 6.1GW in 2012 (Figure 66). Most of these projects are affixed on rooftops of homes or commercial buildings, warehouses and parking lots:

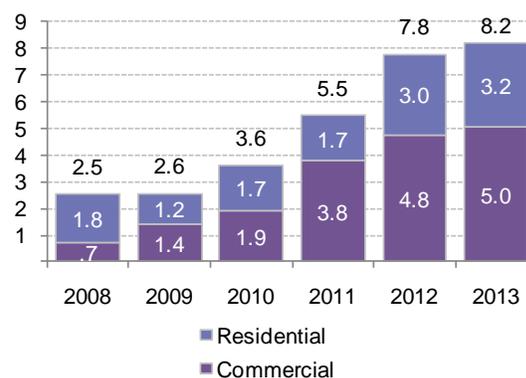
- **Residential (0-10kW):** new residential PV annual installations increased more than a third year over year to an estimated 770MW in 2013. The third-party financing model, wherein a solar provider finances the upfront costs of a PV system for a homeowner in exchange for long-term monthly lease payments, has been a strong driver of new development. The residential market was approximately 20% of annual US PV capacity installed in 2013.
- **Commercial (10-1,000kW):** commercial-scale projects, which totalled 1.2GW in 2013, made up about a third of the market for new PV capacity in 2013. In terms of installed capacity, the commercial sector exceeds the residential sector for several reasons. Most obviously, individual commercial projects are often significantly larger than residential projects. As a result, the economies of scale can be substantial; for example, installers in Massachusetts reported prices of about \$5.00-6.00/W for residential projects in early 2013, compared to around \$3.50/W for commercial projects. These lower prices often translate to better economics on a \$/MWh basis. In New Jersey, for example, commercial-scale development is feasible under current SREC prices, while the economics are much tighter for residential systems. A number of large corporations have made sizable commitments to 'go solar', motivated by some combination of attractive economics, a desire to reduce dependence on the grid, and internal sustainability or carbon reduction commitments. Big-box stores such as Walmart, Costco, and Kohl's are among the largest procurers of customer-sited solar; together, these three companies had installed over 180MW as of mid-2013.

Figure 66: US small-scale PV build by type, 2008-12



Source: Bloomberg New Energy Finance

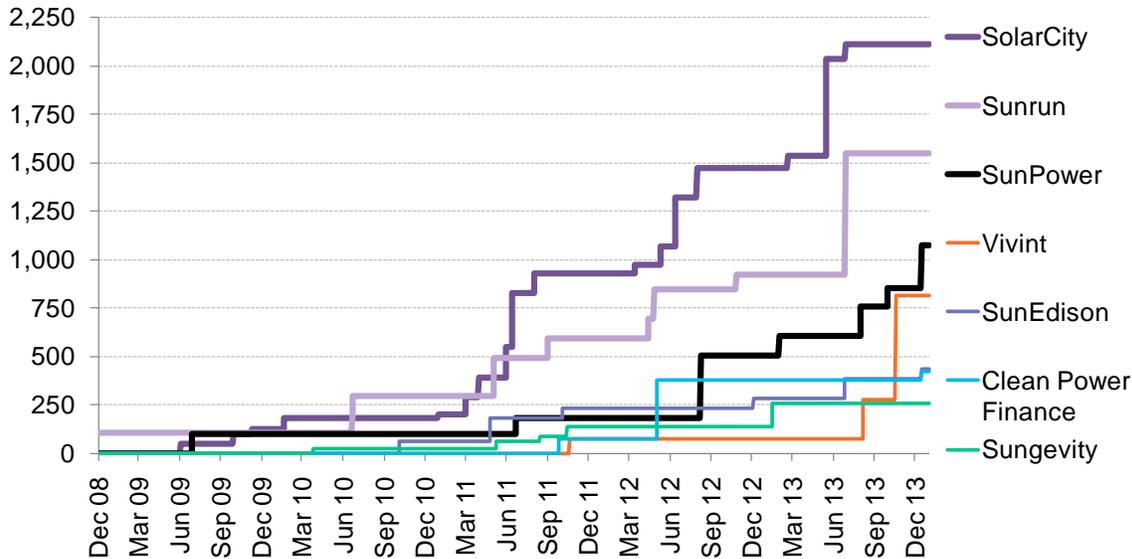
Figure 67: US small-scale solar project financing by type, 2008-12 (\$bn)



Financing

Bloomberg New Energy Finance estimates that funding for small-scale solar reached \$8.2bn in 2013, up from \$2.5bn in 2008 (Figure 67). Much has come in the form of funds raised by third-party financiers such as SolarCity and Sunrun. These funds totalled \$1.7bn in 2012, \$2.7bn in 2013, and \$6.7bn cumulatively since the first of these funds was announced in 2008. Funds can include tax equity, sponsor equity, and debt and are raised with contributions from investors (typically banks). Figure 68 shows cumulative funding closed by the most prolific third-party financiers.

Figure 68: Cumulative funds closed by selected third-party financiers, 2008–13 (\$m)



Source: Bloomberg New Energy Finance Note: This represents fund size; actual capital invested is lower and non-public. Data is from publicly-available documents and submissions from investors; this figure does not capture any undisclosed deals. Each fund contains an unknown combination of equity, tax equity, or debt.

Economics

Residential and commercial-scale solar project costs have declined in the past year, though to a lesser degree than in years past, due to the bottoming-out of panel prices (Figure 69 and Figure 70).

US distributed solar system prices are still well above global levels. In California, installers installed systems atop residential roofs at an average price of about \$5.00/W, while the typical host-owned commercial-scale system in the state cost approximately \$4.20/W. Compared to best-in-class systems in Europe, US projects have higher ‘soft costs’, which include permitting, labor and customer acquisition (US developers may also be more profitable on a \$/W basis than their European counterparts).

Figure 69: Capex – best-in-class cost of global commercial-scale PV, 2010-12 (\$/W)

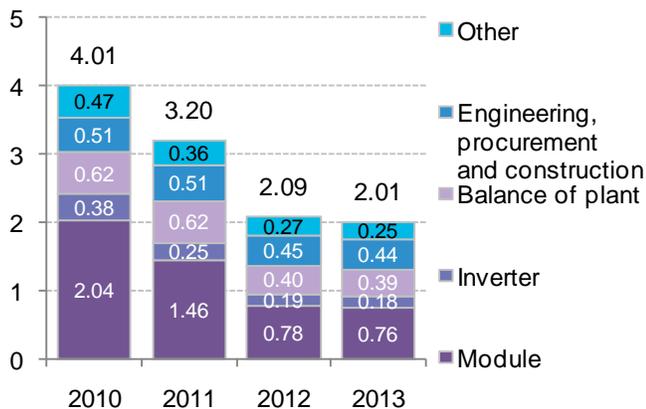
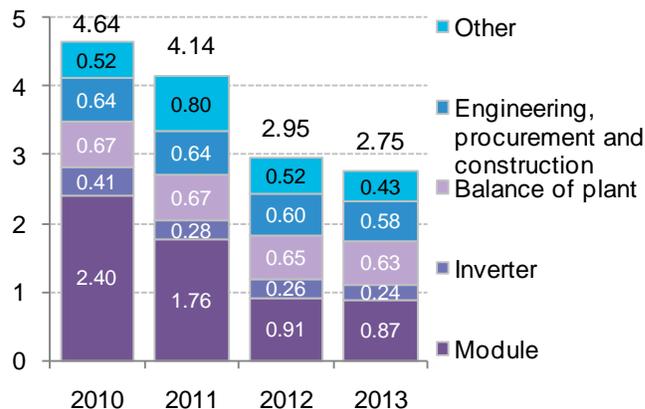


Figure 70: Capex – best-in-class cost of global residential PV, 2010-12 (\$/W)



Source: Bloomberg New Energy Finance

Market dynamics

The distributed solar installer market is fragmented. Of the US installed residential solar capacity in 2013, the majority was third-party financed, led by Sunrun and SolarCity.

Third-party financing continues to grow in the US residential sector; market share for this financing model in California rose from 2% of installed capacity in Q1 2008 to more than two-thirds in 2013. This is not surprising: third-party financing offers homeowners a low upfront cost option to solar ownership. Third-party financing is less common in the commercial segment, because it is more difficult to standardize contracts and because commercial entities may be better able to take advantage of solar tax benefits, relative to individual homeowners. In 2013, only 39% of commercial installations were third-party financed in California.

The small-scale solar industry is also racing to reduce the cost of financing, eyeing it as one of the levers it can operate to improve project economics, especially in preparation for the period beyond 2016 when the ITC benefits are scaled down. A major milestone occurred in 2013 when SolarCity launched a first-of-a-kind solar securitization (Section 8.5).

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. A similar figure was not available for 2012 or 2013.

Medium-scale wind (100kW-1MW)

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

Deployment

Small-scale wind (<100kW)

In 2012 the US installed 18.4MW of small-scale wind capacity, according to data compiled by the Pacific Northwest National Laboratory (Figure 71). In capacity terms, this was comparable to 2011 levels and 28% down from 2010. In units sold, however, the decline in installations was much larger. There were only 3,700 small wind units sold in 2012, down 49% from the 7,303 units sold in 2011 and 53% from 2010. This was a result of a move toward larger turbines in the sub-100kW market. The average size of the small wind turbine installed nearly doubled in 2012 from the year prior, up to 4.97kW from 2.61kW.

Nevada, Iowa, Minnesota, Alaska and New York led the states in installing the most small wind capacity in 2012. Nevada installed the largest amount, mostly through sales of refurbished turbine equipment that became available when some old California wind farms were repowered with newer turbines.

Figure 71: US small-scale wind build, 2002-12

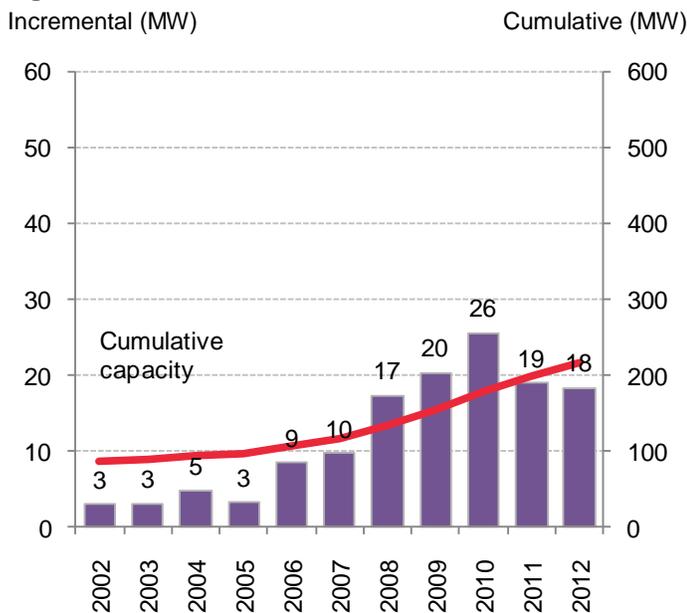
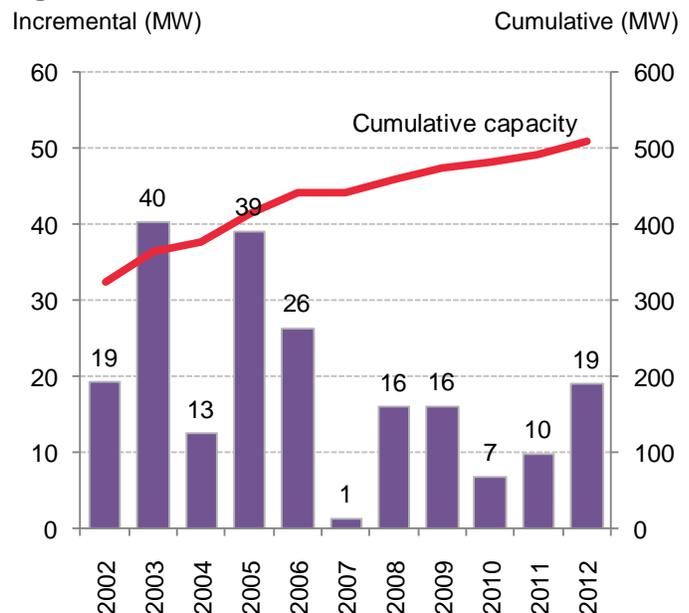


Figure 72: US medium-scale wind build, 2002-12



Source: Bloomberg New Energy Finance, American Wind Energy Association, Distributed Wind Energy Association, eFormative, Pacific Northwest National Laboratory, US Department of Energy

Medium-scale wind (100kW-1MW)

Demand for medium-scale wind increased in 2012 to 19MW, bringing cumulative capacity to 510MW (Figure 72). The deployment in 2012 was higher than in the previous two years but half the level of the 40MW peak reached in 2003.

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 the fact that incentives come in

the form of tax credits can make project ownership unattractive or unviable. In the residential solar business, 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)

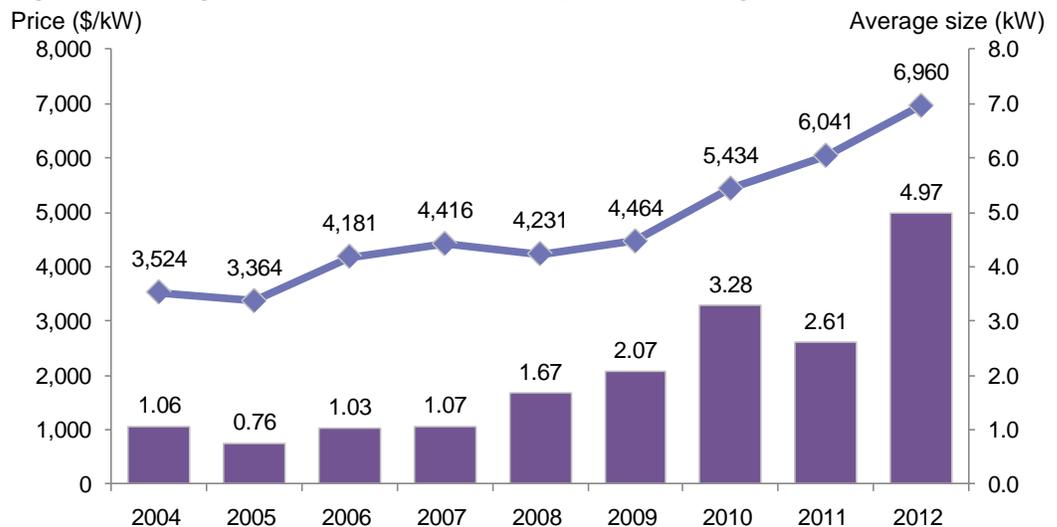
Due to the low volume of new build in recent years, financing activity has been limited in the medium-scale wind space. The majority of projects are owned by schools, government or non-profit agencies. Improved financing packages are needed to aid growth as upfront costs are high. Few companies offer lease arrangements and loan programs are limited.

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 65% from 2008 to 2012 (Figure 73).

Figure 73: 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. The average installed cost of projects between 101kW and 850kW declined from just over \$4,000/kW in 2011 to just under \$3,000/kW in 2012. Costs for projects of 0.9-5MW also declined, albeit more modestly, from \$3,000/kW to just under \$2,900/kW.

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. The export market, which had been a bright spot amid declining domestic demand, is facing increased competition from international suppliers. Small wind exports were down nearly 50% from 2011 to 8MW in 2012, after experiencing a 200% increase from 2010 to 2011.

Medium-scale wind (100kW-1MW)

Medium-scale wind grew 50% in 2012 from 2011 driven in large part by a final push to take advantage of the expiring cash grant program. Demand could increase from the farming sector due to USDA grant and loan guarantee programs for agricultural producers and rural small businesses.

5.3. Small-scale biogas

This section considers small-scale biogas deployments – specifically, anaerobic digestion installations that are mostly less than 1MW in size.

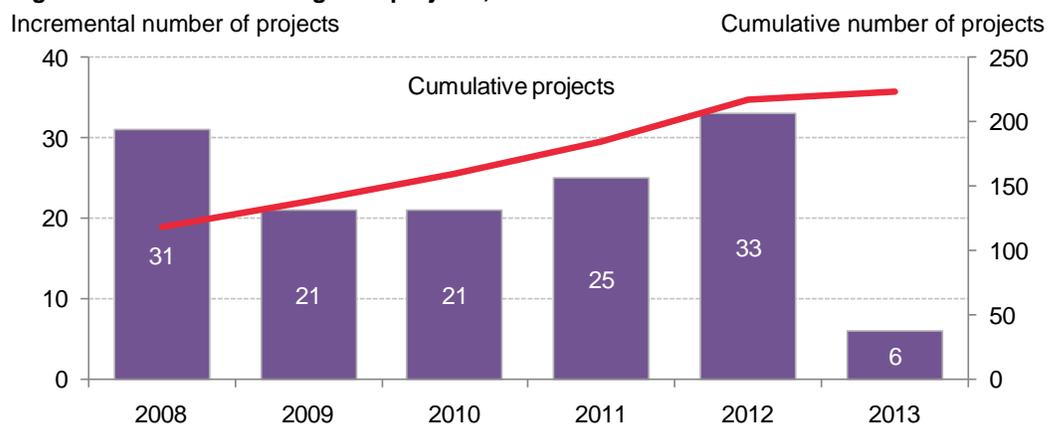
Policy

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

Deployment

As of year-end 2013, there were 224 operational farm-based anaerobic digestion plants with a combined electricity production capacity of around 109MW. Roughly 190 projects were smaller than 1MW, and in total offered some 52MW of electricity capacity.

Figure 74: 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 unsubsidized LCOE of anaerobic digestion projects varies very significantly, in a range of \$27-209/MWh (with LCOE for a typical project at \$146/MWh). This pricing makes for expensive renewable energy on a utility scale, but distributed projects can be competitive with more expensive retail rates. The analysis does not assume any cogeneration, which can provide additional benefits to project owners.

Market dynamics

Small-scale anaerobic digestion is often seen as a sustainable and environmentally friendly way to manage livestock manure and other organic residues. It can be easily employed as an on-site, on-farm solution. The vast majority of small biomass projects (181 of the 224 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, beef, poultry, and mixed farms.

The average electricity-generating project size rose from 230kW in 2003 to 748kW in 2011 then fell to 432kW in 2013. This increase has been driven by new development at larger farms.

5.4. Combined heat and power and waste-heat-to-power

Policy

CHP facilities/units generate both 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 with 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 government offers some support to CHP, though this support 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. As noted below, this legislative change led to a sharp decline in deployment for CHP systems larger than 100MW. Currently, the chief federal incentive for CHP is a 10% ITC, which expires in 2016; it is available to the first 15MW of projects up to 50MW in capacity that exceed 60% energy efficiency. Waste-heat-to-power projects are not eligible for this tax credit. Further federal support appears to be on the way. The EPA and DOE are actively pursuing an initiative to increase CHP deployment as part of a compliance strategy under a regulation limiting emissions from coal- and oil-fired industrial boilers, and President Obama signed an Executive Order in 2012 calling for a goal of 40GW of new CHP capacity by 2020. According to ICF International, technical potential for CHP development in the US is estimated to be just over 125GW for onsite use.

Additional incentives exist at the state level; 24 states allow CHP or waste-heat-to-power to be eligible for RPS, alternative energy portfolio standards, or energy efficiency resource standards (these policies are explained in Section 6.1).

Deployment

CHP projects tend to be customized to supply a specific consumer with both electrical and thermal energy demand. They can be small and provide distributed generation, or large, utility-scale installations, which sell electricity back to the grid.

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 the PURPA changes as well as to other factors including stagnant US electricity demand, sluggish industrial growth, and (around 2008) high natural gas prices; cumulative capacity even dropped as industrial plants with CHP units shut down during the economic downturn. Yet deployment seems to have re-embarked on an upward trajectory, with 870MW installed in 2012 (Figure 75) and another healthy year likely to have occurred in 2013.¹¹ CHP plants represent 8% of US generating capacity and produce at least 300TWh of electricity per year (Figure 76).¹²

Figure 75: US CHP build, 2008-12

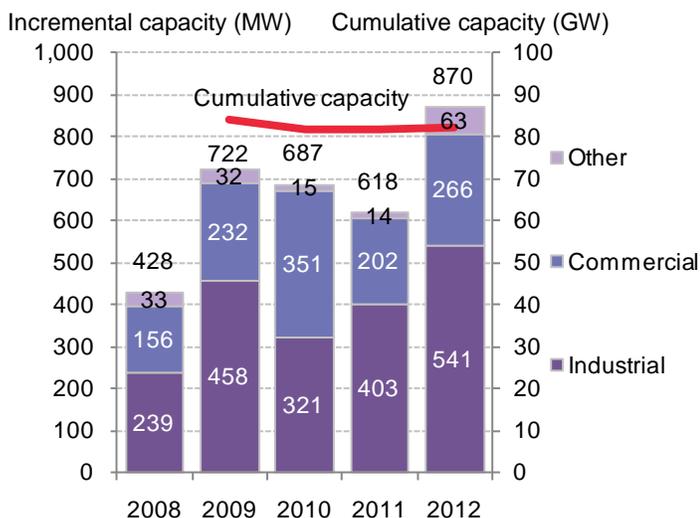
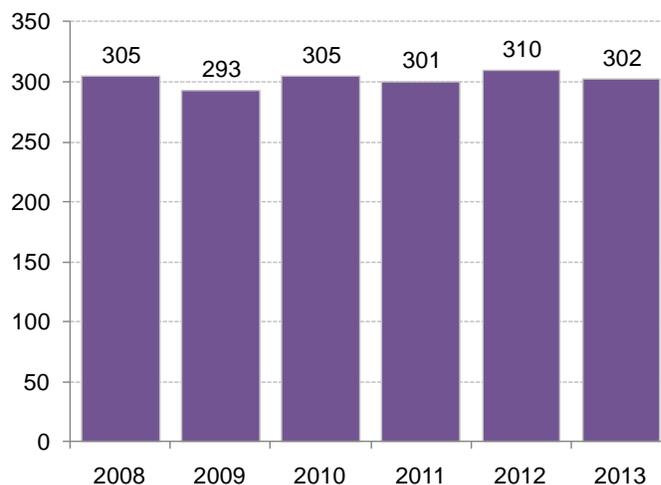


Figure 76: US CHP generation from plants tracked by EIA generation data, 2008-13 (TWh)



Source: CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory. Notes: Cumulative capacity was higher in through September 2013 and has been seasonally adjusted to reflect earlier years largely because of closures at industrial facilities that had expected full year amounts. CHP capacity.

Source: Bloomberg New Energy Finance, EIA Notes: 2013 data is generation data. However, EIA data on CHP is not comprehensive and so the generation figures are 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. Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through September 2013).

The industrial sector accounts for most of the existing capacity (Figure 77). 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

11 Final data for 2013 is not yet available, but ICF International estimates that build increased from 2012 levels.
 12 The 300TWh number comes from EIA generation data, but this data is incomplete; see notes under Figure 76.

asset owners such as Dow Chemical, ExxonMobil, and International Paper. This fact also determines plant location: many large CHP plants are located close to petrochemical plants and refineries along the Gulf Coast. While historic capacity has been largely in the industrial sector, studies indicate that comparable or even greater potential may lie in the commercial sector.¹³

Figure 77: US CHP deployment by sector

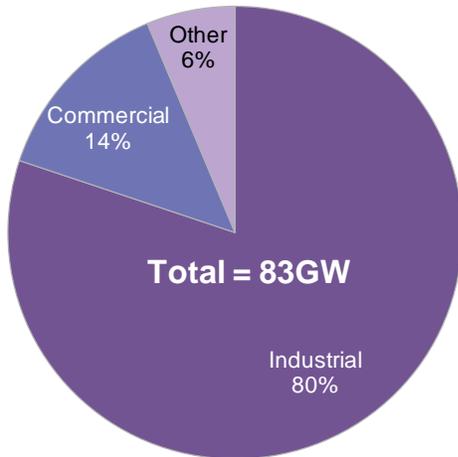
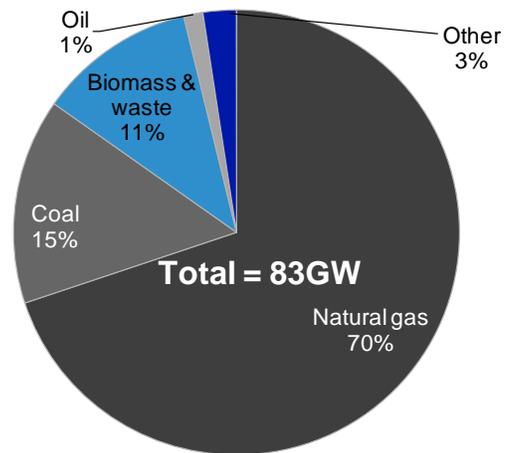


Figure 78: US CHP deployments by fuel source



Source: CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory.

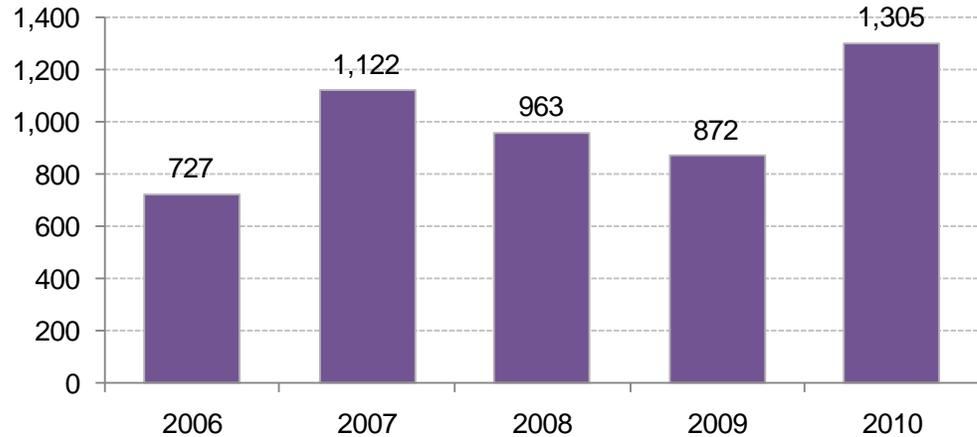
Nationwide, 89% of CHP capacity uses fossil fuels. Natural gas is the primary fuel source due to its low emissions and high efficiency (Figure 78). Renewable energy fuels 11% of capacity, all of it biomass and waste. Many of these projects are located at waste-processing facilities, or at pulp and paper mills, where generators use wood waste from the mill's processes as a feedstock.

Financing

can opt for balance-sheet, debt, equity, or lease financing for their projects. Third-party ownership is also an option, especially for large projects; under this structure, third-party developers (such as Recycled Energy Development, Primary Energy, and Veolia Energy) will own, operate, and maintain projects and sell power back to the industrial host.

Risk aversion, expected returns on investment, required payback periods and transaction costs can all influence decision-making. According to data from ICF International, annual asset finance for CHP projects averaged \$971m per year over 2006-10 (Figure 79).

13 "Recent estimates indicate the technical potential for additional CHP at existing industrial facilities is just under 65GW, with the corresponding technical potential for CHP at commercial and institutional facilities at just over 65GW." DOE and EPA report, *Combined heat and power: a clean energy solution*, August 2012, based on internal estimates by ICF International.

Figure 79: Asset finance for US CHP projects, 2006-10 (\$bn)

Source: CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory. Notes: These figures are estimated assuming a two-year lag between financing and deployment, and assuming a weighted average capex of \$1.7m/MW in 2006, falling to \$1.4m/MW by 2009, and then increasing to \$1.5m/MW in 2010 to reflect a recent trend toward smaller systems. Financing figures are only available through 2010, since deployment figures are only available through 2012 (and there is an assumed two-year lag between financing and deployment).

Economics

The average capex for large-scale (over 40MW) CHP is approximately \$1.3m/MW, compared with 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 unsubsidized LCOE for a natural gas-fired CHP project of this size is around \$60/MWh compared with \$67/MWh for a CCGT plant. Overall, then, for projects that can make efficient use of the heat energy, CHP can be a cost-effective source with lower levelized costs than CCGT.

To calculate the LCOE, Bloomberg New Energy Finance assumes the application of CHP to a standard CCGT facility. It is 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 + 500 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 5.1-7.0MMBtu/MWh, down from 9.5-10MMBtu/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 offer favorable economics. LCOE calculations by Bloomberg New Energy Finance show that small CHP systems (below 10MW) may compete with retail electricity rates if the capacity factor is high enough, and if power prices in the region are high. Achieving high efficiency, however, is only the case if the system is well-sized to a building's electricity and heat demand profiles. Otherwise, electricity production from small CHP facilities may prove very expensive with LCOE of several hundred dollars per MWh. Broadly generalizing, cost profiles for small CHP installations will be attractive as long as capacity factors exceed 60%. Case-specific economics, however, vary greatly.

Figure 80: Capex – capital costs for CHP installations (\$/MW)

Source: Bloomberg New Energy Finance; EPA Combined Heat and Power Partnership, *Catalog of CHP Technologies*, prepared by ICF International. Note: ICF International reports that CHP capex has remained fairly constant since 2008. BNEF data reflect capex for small CHP facilities powered by gas-fired reciprocating engines, gas turbines and microturbines and are based on an internal survey among industry participants.

Market dynamics

Lack of growth in the US industrial sector has restrained new build in the recent past. Barriers to further deployment also include permitting requirements, lack of customer awareness, limited availability of finance, permitting requirements, and a lack of standardized interconnection procedures and nationwide regulations on stand-by and back-up charges.

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. These low prices are also supporting the development of new petrochemical plants by companies such as Dow Chemical, LyndonBasell and Sasol – especially in Gulf states – which could become locations for new CHP projects. Against this backdrop, the CHP market seems to be rebounding from a slump that began in 2006. Announced project numbers have increased and imply that more than 3,000MW of CHP capacity could be installed annually by 2016, according to ICF International. This is about equal to cumulative installed capacities over the past five years.
- Concerns about energy outages during emergency situations and weather events are prompting interest in CHP, especially in the wake of Hurricane Sandy. The number and costs of weather-related natural disasters rose over the last decade, especially in the Northeast US, with storms accounting for over half of all power outages, according to Munich Re. Over 90% of outages occur at the distribution level of the grid and 98% of the costs of outages are borne by commercial and industrial customers, making self-generation more cost-effective for the non-residential sectors. CHP facilities increase power reliability and ensure continuous operation during hurricanes or other contingency events.¹⁴

14 Additional information regarding CHP resiliency during storms such as Hurricane Sandy can be found in ICF International's May 2013 report, *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities*.

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 the end of 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.

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 fueling by renewable hydrogen or biogas.

Several states have specific grant funding available for fuel cell projects. California's Self-Generation Incentive Program offers a \$2,025/kW grant for fuel cells installed on the customer's side of the meter with a 20% bonus on the incentive for customers who use a California supplier (benefiting local fuel cell maker Bloom Energy significantly). New Jersey had incentives for CHP and fuel cell projects ranging from \$2.25-4.25/W. Though that program expired in June 2013, it is now being restructured for fiscal year 2014. New York State offers financial incentives up to \$50,000 for customer-sited fuel cells less than 25kW and up to \$1m for systems larger than 25kW. Pennsylvania has funding available for fuel cell projects of any size up to \$2m, or 30% of project costs. In July 2011 Delaware enacted S.B. 124, which allows for qualified fuel cell projects to generate one REC for each megawatt-hour of electricity produced as well as allowing for the conversion of six fuel cell RECs to be converted into one solar REC (SREC), up to 30% of SREC requirements. Connecticut also has a number of tax credits, net metering and funding vehicles to incentivize fuel cell projects.

Deployment

Years of research into stationary fuel cells are gradually bearing fruit; costs are falling and the number of installations is on the rise. Over the past five years, an average of 27MW of new stationary fuel cell projects were deployed in the US annually, bringing cumulative installed capacity for active stationary fuel cell installations to over 140MW (Figure 82).

There are five types of fuel cell, differentiated by their underlying electrochemistry (Table 3). Molten carbonate (MCFC) and phosphoric acid fuel cells (PAFC) are the closest to commercial viability specifically for grid-scale applications. Solid oxide fuel cells (SOFC) are more versatile and are in development for stationary, portable, and auxiliary power unit applications. Polymer electrolyte membrane (PEM) 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.

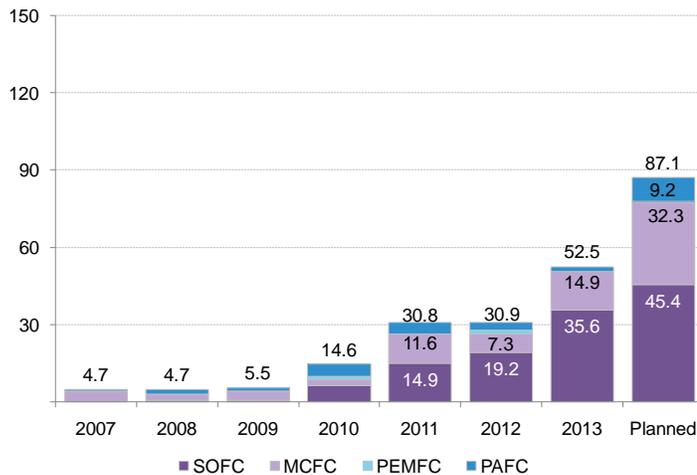
Table 3: Comparison of fuel cell types

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	45-50%	Distributed generation, utility	FuelCell Energy
Phosphoric acid (PAFC)	100kW–400kW	40%	Distributed generation	n.a.
Polymer electrolyte membrane (PEMFC)	1kW–100kW	35-60%	Backup power, distributed generation, transportation	Plug Power, Alteryg, ClearEdge Power
Solid oxide (SOFC)	1kW–2MW	60%	Distributed generation, utility	Bloom Energy

Source: Bloomberg New Energy Finance, US DOE

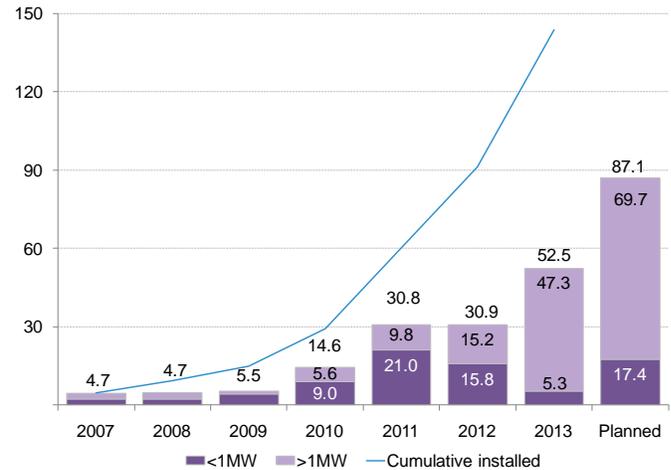
MCFCs, SOFCs and PAFCs have been deployed the most broadly in the US for projects larger than 100kW (Figure 81) led by FuelCell Energy (MCFCs) and Bloom Energy (SOFCs).

Figure 81: US stationary fuel cell capacity, installed and planned, by technology, 2007-13 (MW)



Source: Bloomberg New Energy Finance

Figure 82: US stationary fuel cell capacity, installed and planned, by size of installation, 2007-13 (MW)



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

Projects below 100kW cover applications such as back-up and auxiliary power for commercial and industrial installations. Systems smaller than 10kW are primarily for residential and small- and medium-sized enterprise applications, but have become less popular in recent years. Instead, there has been a shift toward 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, a record 70 projects were commissioned, 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. In 2012, 39 projects were built, 33 of which were larger than 100kW. In 2013, 12 projects were installed totaling 52.5MW with only a single project at or below 100kW. Remaining projects were, on average, 4.8MW each, ranging in size from 400kW to over 20MW.

There is currently a total project pipeline of 87.1MW spread over the next three years. A total of 16 of 34 announced projects are over 1MW, with the single largest being Bloom Energy's Red Lion facility in Delaware, with a total output of 27MW, 23MW of which was commissioned by the end of 2013.

In Bridgeport, Connecticut, a 14.9MW plant developed by FuelCell Energy for Dominion Resources broke ground in May 2013 and was completed by December. FuelCell continues to serve as the project's operator with Connecticut Light & Power as the offtaker under a 15-year contract. Connecticut also was the first state to solicit numerous microgrid project proposals in a public request for proposals. Of 27 proposals reviewed, nine were awarded grants in July 2013. This included two projects which make use of 400kW fuel cell installations paired with PV or natural gas generators. These projects are expected to be installed in the next several years.

US fuel cell deployment has largely aligned with policy with the largest amount of activity occurring in states with attractive incentives (Figure 83 and Figure 84).

Figure 83: California stationary fuel cells annual capacity installed, 2007-13, by major supplier (MW)

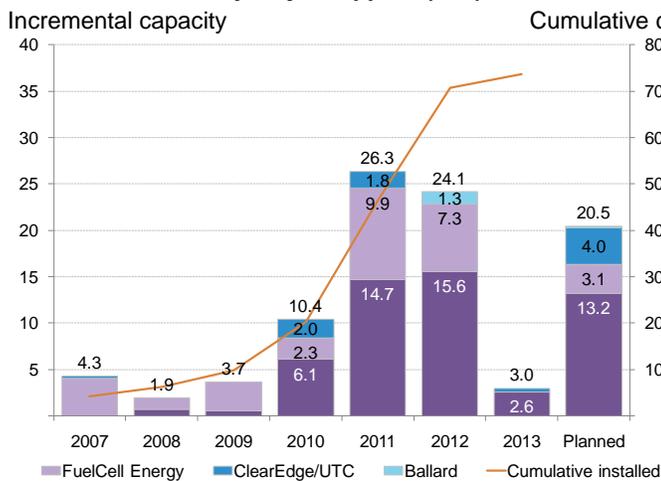
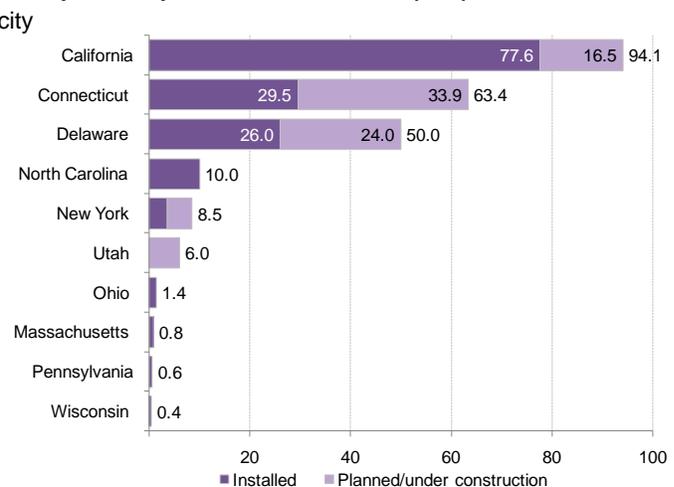


Figure 84: Stationary fuel cell capacity in top 10 US states, 2007-present, planned and installed (MW)

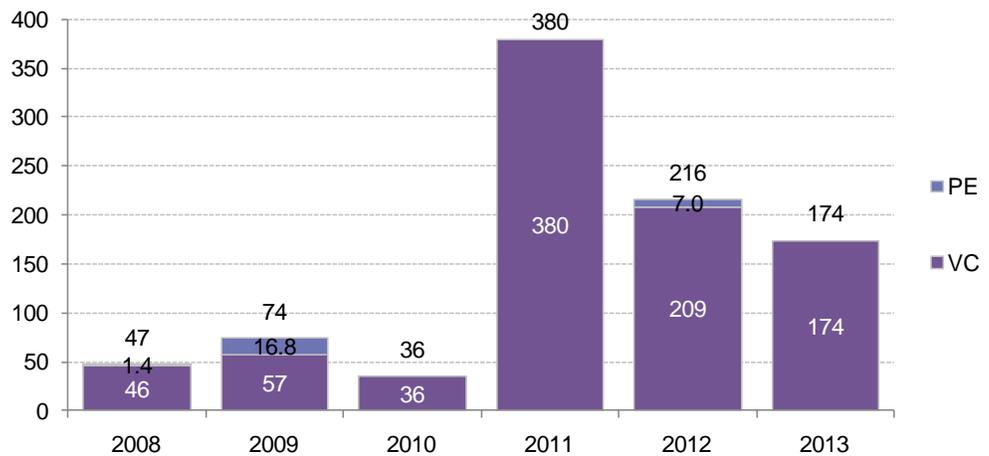


Source: Bloomberg New Energy Finance Note: 'Planned' refers to projects which are announced and are at various stages of development.

Financing

Fuel cells have garnered significant attention from the venture capital community. In 2011, there was a record investment of \$380m (Figure 85) 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 2013, raising \$130m from Credit Suisse. The year's other large investment was a \$36m G round raised by ClearEdge Power in March. Other companies raising venture capital in 2013: Akermis, Apollo Energy Systems and WATT Fuel Cell.

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 85: Venture capital / private equity investment in US fuel cell companies, 2008-13 (\$m)

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

Economics

Stationary fuel cells from players such as Bloom, ClearEdge and FuelCell 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 Utilities Commission indicate that all-in capex ranges from as low as \$5.8m/MW to as high as \$16.8m/MW, yielding an unsubsidized LCOE of \$126-303/MWh. However, incentives and the avoided costs of purchasing grid electricity make fuel cell projects far more attractive, bringing the LCOE range to \$115-253/MWh on a subsidized basis. 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 fueled 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 low natural gas prices, availability of the federal ITC 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), Connecticut (due to several funding mechanisms and tax incentives) and Delaware (due to the contract signed by the state with the local utility Delmarva and Bloom Energy).

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 (68MW). The company's success partly stems from its "Bloom Electrons" business model, which allows customers to sign long-term PPAs with Bloom for electricity from its fuel cells, rather than having to purchase the fuel cell systems outright. Bloom has stated that, with certain state and federal incentives, it can offer customers PPAs 5-20% below retail rates.

With a pipeline of 219MW under development, FuelCell Energy, via its partnership with South Korea's POSCO Energy, has the largest development portfolio globally. With an eye on sub-megawatt

applications to complement its molten-carbonate fuel cell products, FuelCell acquired solid-oxide fuel cell manufacturer Versa Power Systems in December 2012.¹⁵ 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.

ClearEdge acquired UTC Power in December 2012.¹⁶ In addition to manufacturing phosphoric-acid fuel cells systems for applications above 100kW, UTC makes PEMFCs for transportation applications and AFCs for military and space applications. The combined entity will be able to compete across a broad array of applications.

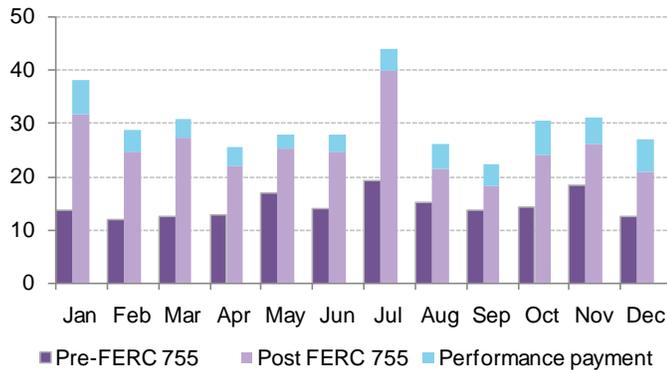
5.6. Energy storage

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 resources¹⁷ for the actual quality and quantity of regulation provided; this compensation is called the ‘performance payment’.

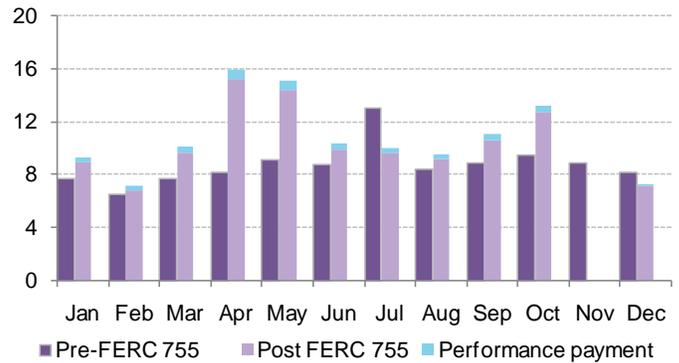
By the end of 2013, Order 755 had been implemented in four US power markets: PJM (consisting of 13 states in the northeast US), MISO (the Midwest), NYISO (New York) and CAISO (California). The impact on prices has varied in each region based on the exact price calculation methodology adopted, but overall average prices have increased between 23% and 104%, with the most lucrative market being PJM (Figure 86 and Figure 87). NYISO and CAISO implemented FERC Order 755 in the summer of 2013 making it difficult to draw conclusions over such a short period.

Figure 86: Average PJM regulation prices before and after FERC 755 implementation (\$/MWh)



Source: PJM, Bloomberg New Energy Finance Note: PJM implemented FERC Order 755 in October 2012. ‘Regulation prices’ are the prices that resources are paid for providing frequency regulation.

Figure 87: Average MISO regulation prices before and after FERC 755 implementation (\$/MWh)



Source: MISO, Bloomberg New Energy Finance Note: MISO implemented FERC Order 755 in December 2012; as a result post-FERC 755 data in December is from 2012 and November 2013 is not yet available.

15 FuelCell previously already owned 39% of Versa. In December 2012, it acquired the remaining shares.
 16 This acquisition actually came at a cost to the seller, UTC. As explained in UTC’s filings, “The disposition resulted in payments by UTC totaling \$48m, which included capitalization of the business prior to the sale and interim funding of operations as the buyer took control of a loss generating business.”
 17 Frequency regulation resources are responsible for ensuring that the alternating current in the electricity grid stays within relatively tight bounds

California has also been a trailblazer in providing policy support for power storage technologies, offering some of the most ambitious incentives and subsidies in the US. Table 4 details the structure and status of the three most important storage policies in California.

Table 4: California energy storage incentives and subsidies

Policy	Timeline	Status	Structure	Notes
AB 2514	2010-24	Signed into law, storage procurement mandate announced and in effect	Establishes 1.3GW energy storage target for investor-owned utilities to be procured between 2014 and 2020 and installed by 2024; other retail electricity providers must procure storage for 1% of peak demand	First public solicitation deadline for investor-owned utilities is 1 December 2014 New pumped hydroelectric energy storage projects under 50GW are eligible Utilities may defer up to 80% of the mandated storage capacity if they can demonstrate that storage is not operationally or economically viable Several existing projects installed after January 2010 are eligible to be included
Self-Generation Incentive Program (SGIP)	2001-16	Active	Provides \$1.80/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 Energy storage became eligible for SGIP funding in 2009 and must be capable of two hours of performance at its rated capacity at least once per day
Permanent load shifting (PLS)	2006-14	Active	Provides \$0.875/W incentive to end-users, up to \$1.5m per project 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

Since energy storage became eligible to receive SGIP funding in 2009 in California, 769 project applications have been filed, with over 600 filed in 2012 and 2013. Energy storage projects are typically paired with a qualifying generation resource, such as a small gas turbine, fuel cell, wind turbine or PV system, though 88% of paired projects combine with small (5kW) residential PV projects. Despite this, only four projects to date have actually received funding. Nearly 600 remaining applications remain in some stage of the SGIP approval process.

At the federal level, the Advanced Research Projects Agency-Energy (ARPA-E) has invested \$100m in fundamental research in energy storage since 2009 with most of its projects still at early research and development stages. The American Recovery and Reinvestment Act of 2009 provided \$185m for energy storage demonstration projects, which was used to leverage an additional \$400m in private sector support. Four of these projects were completed by the end of 2012, an additional seven came online in 2013, and another three are anticipated to be commissioned before the summer of 2014. The two remaining projects are expected to come online over the next several years. While there is yet little operational data from the projects recently commissioned, the projects were delayed from their initial schedules by an average of 325 days, highlighting the difficulties in commissioning new energy storage projects with first-of-a-kind technologies.

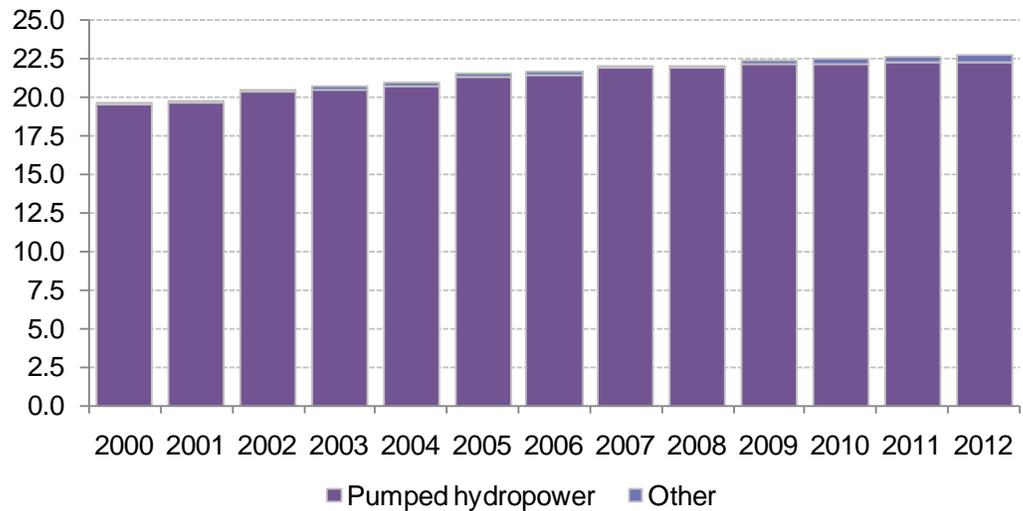
The US Department of Defense, NASA, the National Science Foundation, and the EPA each also have programs that can support power storage technology development. Funding from these agencies totalled more than \$1bn from 2009-12. Most of their programs include storage as a technology eligible to receive grants, but they are not exclusively focused on storage.

Deployment

Pumped hydropower makes up almost the entirety of the US energy storage market, with 22.3GW of installed capacity (98% of existing total storage capacity). It also comprises the bulk of new capacity: net summer capacity for pumped hydro has increased by 2.8GW since 2000 compared to 0.3GW for

other forms of energy storage. Overall, energy storage capacity in the US grew 16% from 2000 through 2012 (the last year for which complete data was available).

Figure 88: Cumulative energy storage capacity, 2000-12 (GW)



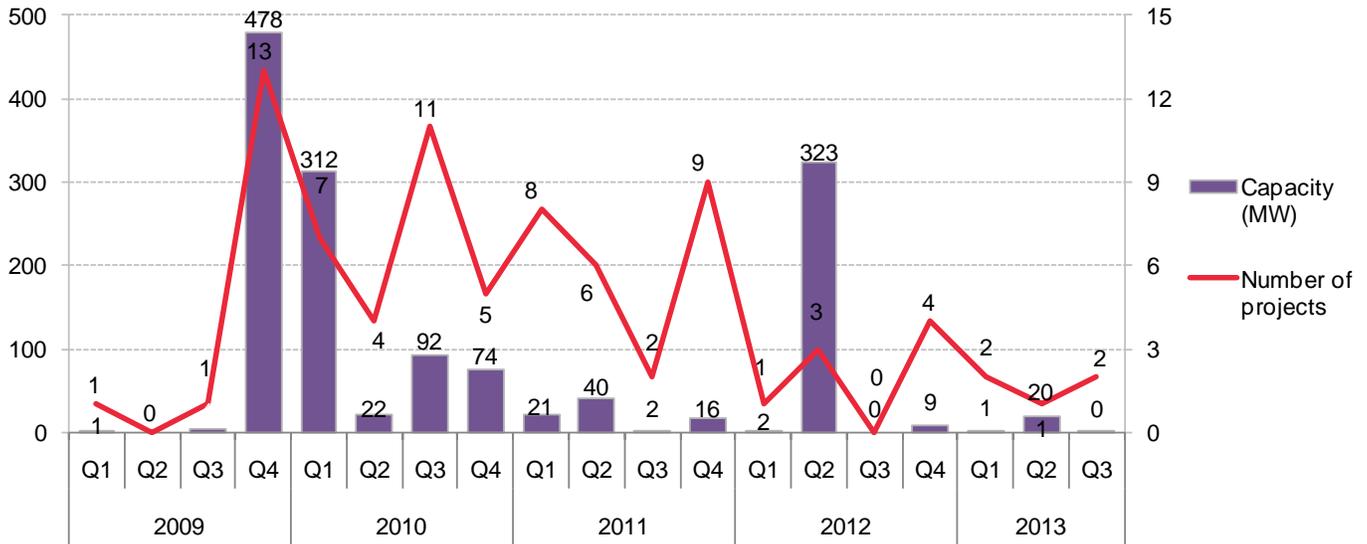
Source: Bloomberg New Energy Finance, EIA Note: Pumped hydropower capacity is net summer capacity.

Capacity offered by non-hydropower storage technologies – including batteries, flywheels, and compressed air – still represents just a small sliver of overall capacity but has grown from 136MW to 409MW over the past decade, with 100MW installed in 2013 alone. Stimulus funding helped promote new technology development, but many projects that received support still await commissioning. Meanwhile, the number of newly announced projects remains low (Figure 89).

Four major obstacles stand in the way of further adoption of storage technologies:

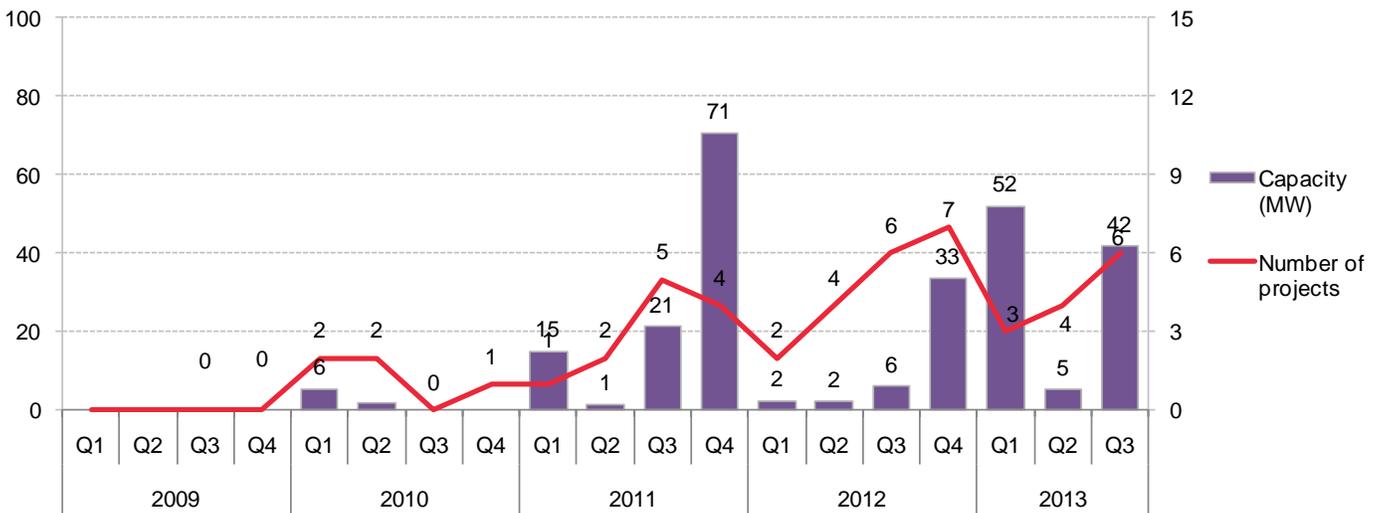
- *Market structure:* markets do not always compensate providers of storage with a premium for the special benefits they offer (fast ramp-up times and the ability to absorb energy in periods of excess output from intermittent resources).
- *High cost:* with the exception of lithium-ion batteries, there have not been significant cost reductions for most commercially available energy storage technologies.
- *Unclear application value:* while a significant number of utilities and other potential buyers have launched pilot energy storage projects, it will take time for them to assess the true value of storage and to inform further, larger-scale purchases.
- *Challenges posed by natural gas:* low natural gas prices drive down the prices for frequency regulation, a service provided by storage assets. In addition, low natural gas prices drive down locational marginal prices, thus yielding less revenue for storage assets participating in wholesale demand response markets.

Figure 89: Announced non-hydropower energy storage projects in the US (MW and number of projects)



Source: Bloomberg New Energy Finance

Figure 90: 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 pumped hydropower, most new technologies are significantly more expensive. In the past few years, however, costs have declined (with the caveat that data reported by technology developers are typically somewhat lower than actual project costs) (Figure 91 and Figure 92). Among advanced energy storage technologies, lithium-ion batteries are the most well understood and deployed due to increased production directed at electric vehicle applications. However, the economics of vehicle applications for lithium-ion batteries differ from the economics for non-vehicle applications; lithium-ion batteries are cheaper per kilowatt-hour when used for electric vehicles than when used for stationary

storage systems due to costs associated with power electronics, control systems and other module components. The scale of deployment for these components has been higher for vehicle systems than for stationary storage systems.

Figure 91: Capital costs of select storage technologies – technology developer estimates (\$/kWh)

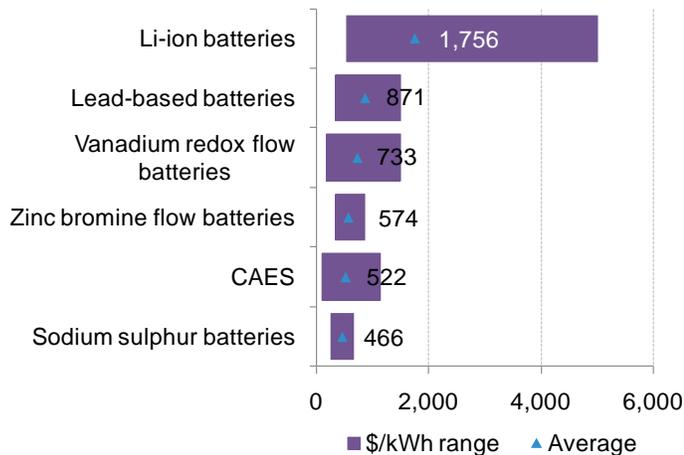
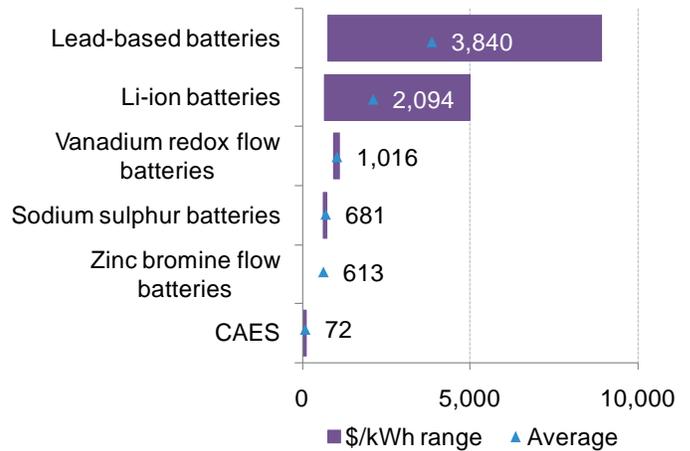


Figure 92: Capital costs of select energy storage technologies – actual project data (\$/kWh)



Source: Bloomberg New Energy Finance. Notes: Lead-based batteries include systems offered by providers such as Xtreme Power and East Penn, not conventional flooded lead acid batteries. 'CAES' refers to compressed air energy storage. These economics refer to stationary storage applications.

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 makes economic sense. The cost of storage systems is higher than the potential revenue gained, even with the implementation of FERC Order 755. However, the continued decline of technology costs and a rise in natural gas prices could turn frequency regulation into a profitable market segment throughout several of the US ISOs. In fact, since July 2013, 24MW of new capacity in the US came online to provide frequency regulation.

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, and demand response from load reduction remains cheaper on its own than energy storage technologies providing the same service.

Storage is being deployed in the residential, commercial and industrial space using zero upfront capex and long-term financing business models borrowed from the distributed solar industry. SolarCity, using Tesla batteries, accounted for 76% of the 2013 California SGIP energy storage applications. California-based Stem, which recently announced \$5m in financing available for 10-year lease contracts for energy storage systems, accounted for 17% of the 2013 SGIP energy storage applications.

Other energy storage applications, including those focused on deferring upgrades to transmission and distribution infrastructure or aimed at renewable integration, still require significant regulatory changes for the financial benefit of storage to be recognized.

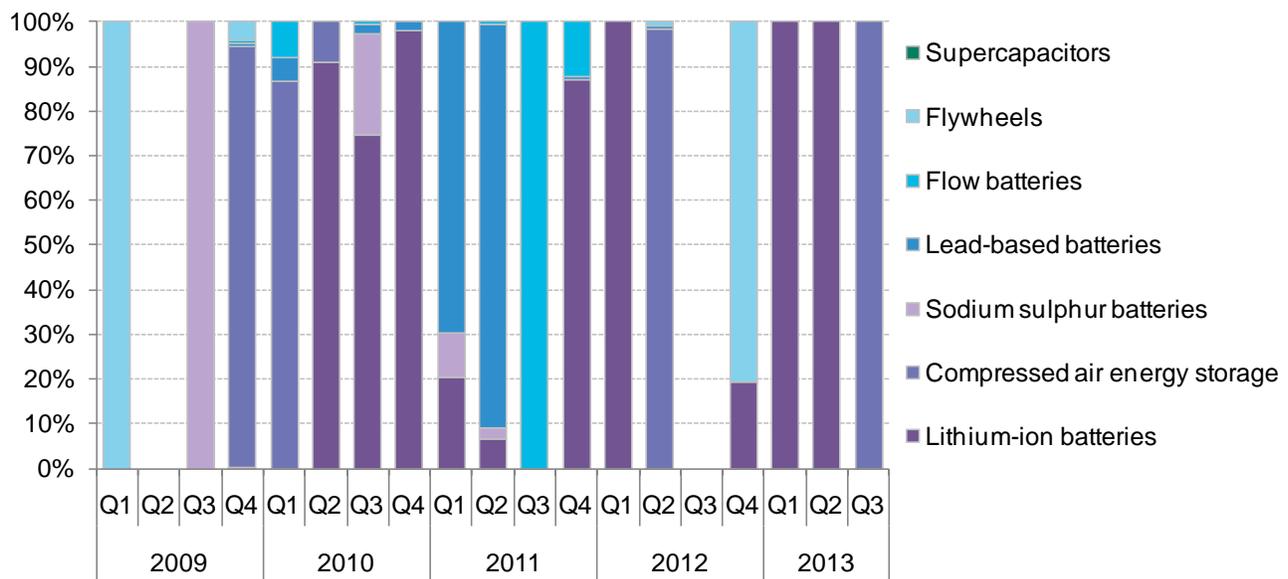
Market dynamics

Developer interest in pumped storage technology has risen in recent years: FERC received 110 preliminary permit applications from 2008-11, compared with just 16 the prior four years. However, in

2012, FERC received only 12 applications. Over 50 projects in 21 states totaling 48GW in capacity had received preliminary permits as of August 2013, though not all will be built.

Among non-hydropower technologies, compressed air energy storage is the leader in terms of installed capacity. Yet 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. Over the last several quarters, lithium ion battery projects have dominated the scene (Figure 93). This is the technology that has seen the most progress, with US companies such as A123 Systems having pioneered technology improvements (though not without risk, as demonstrated by A123's bankruptcy in 2012) and installed a significant amount of US-based manufacturing capacity.

Figure 93: Non-hydropower announced energy storage projects in the US by technology (% by MW)

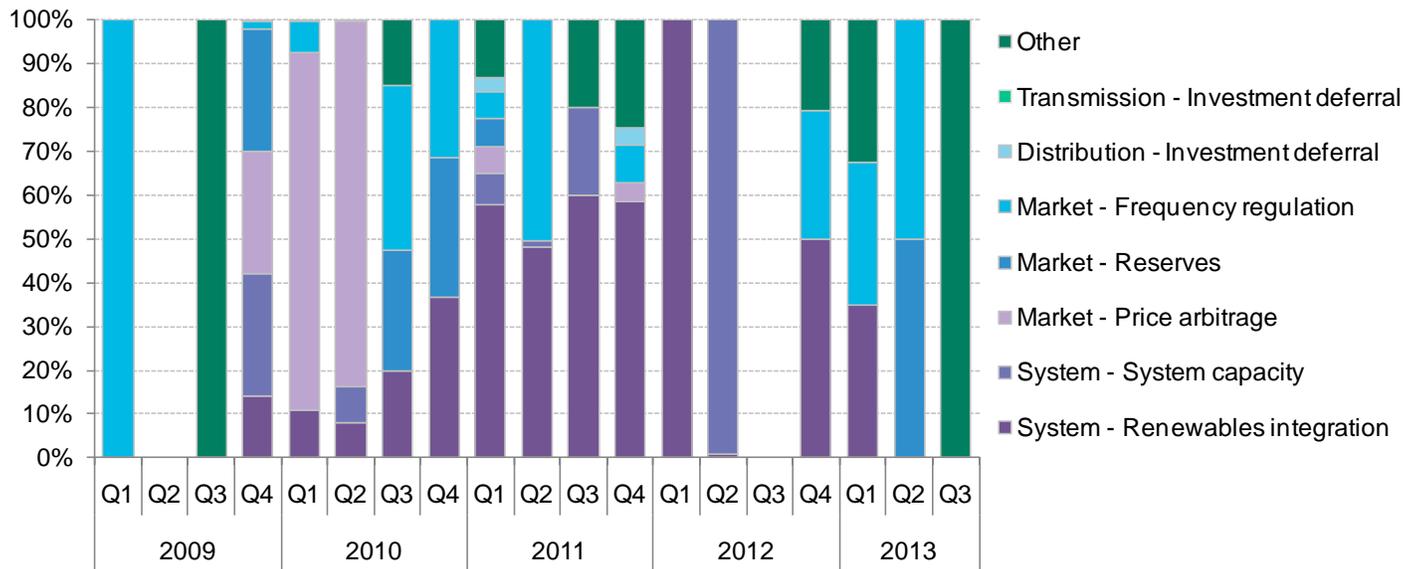


Source: Bloomberg New Energy Finance Note: Pumped storage is not included in this chart as it would dwarf all other technologies. Empty columns represent quarters where there were no new projects announced.

In terms of the *application mix*, in recent years, the storage sector has increased its focus on renewable energy integration, but most of these projects are demonstrational and not necessarily economical. Frequency regulation has become a major application in three of the last four quarters (Figure 94). 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.

Two companies have led the battery market so far: A123 Systems and Xtreme Power. Despite its October 2012 bankruptcy filing, the former has been particularly dominant in the frequency regulation segment through its partnership with AES Energy Storage. Xtreme, after installing over 50MW of its advanced lead-based batteries in the US, announced in spring 2013 that it will exit the battery business and focus on software for grid storage integration. It has already inked partnerships to integrate its software with GE and Samsung SDI energy storage systems.

Figure 94: Non-hydropower applications for announced energy storage technologies in the US (% by MW)



Source: Bloomberg New Energy Finance Note: Pumped storage is not included in this chart as it would dwarf all other technologies. Empty columns represent quarters where there were no new projects announced. Other refers to 13 applications not individually separated.

5.7. Carbon capture and storage

Policy

The US has no federal policies explicitly mandating CCS usage at power or industrial plants, but newly drafted regulations on the power sector would potentially compel developers of new coal-fired power plants to use the technology. New rules expected in 2014 should mandate that currently operating plants also cut their CO₂ emissions. Again, this could steer plant operators to consider CCS. In addition, the federal government offers loan guarantees and tax credits intended to spur adoption of the technology. Finally, there has been some policy support from a handful of states.

In September 2013, the EPA released the latest draft of its New Source Performance Standards. The standards ban plants that emit more than 1,000lbCO₂/MWh,¹⁸ corresponding to about a 50% CO₂ emissions reduction on unabated coal-fired power. This level can be achieved by combined cycle gas plants without additional controls, but new coal-fired plants would require CCS to be in compliance. This standard is not expected to drive a CCS market, however, as the technology requires significant additional expenditure over base coal plant costs. Instead, new thermal power plant build in the US will likely be dominated by gas plants without CCS.

The DOE Loan Programs Office launched a new \$8bn solicitation for advanced fossil energy project loan guarantees on 12 December 2013. Along with CCS, the program also includes advanced resource development, low-carbon power systems, and efficiency improvements. There are only a couple of power-generating CCS projects that are advanced enough to be able to take advantage of the guarantees – Summit Texas Clean Energy Project and SCS Hydrogen Energy California – which means that more of the \$8bn may go to advanced resource development projects, which are focused on oil and gas production. Initial responses to the solicitation are due by end-February 2014.

18 Or 1,100lbCO₂/MWh for plants with a higher heat rate, such as simple cycle gas turbines.

The federal government also currently offers a '45Q' tax credit for CCS installations. The credit, created under the Emergency Economic Stabilization Act of 2008, ranges from \$10/tCO₂ for CO₂-enhanced oil recovery (CO₂-EOR) projects to \$20/tCO₂ for geologic storage without any associated hydrocarbon production. As of late 2012, the program had only been about 30% subscribed (approximately 20.8MtCO₂ out of 75MtCO₂ authorized). In early 2013, the government announced a new \$150m in the 48C program (manufacturing tax credits) for which CCS equipment manufacturers are eligible.

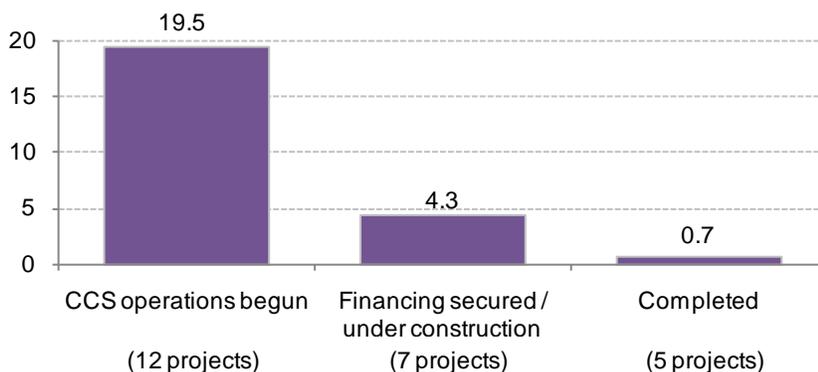
Illinois is the only state with a specific portfolio standard for coal-fired CCS power plants, though other states have provisions for CCS in their portfolio standards or goals. Illinois requires utilities to source a portion of their total electricity supply, starting at 5% in 2015 and increasing thereafter, from coal plants with CCS (minimum 70% CO₂ capture rate). Two projects are currently in development, but it is unlikely that 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 CO₂ 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 CO₂ that would otherwise have been released. This includes projects that separate CO₂ from natural gas processing facilities and from chemical plants (eg, plants involved in fertilizer production and hydrogen production) and that inject that CO₂ for EOR. The threshold is projects that are 'pilot scale' and larger, defined as greater than 10 megawatts equivalent (MWe). This definition for CCS is not necessarily an industry consensus; other industry experts draw the line more tightly, counting only projects which capture CO₂ 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 CO₂ 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 15MtCO₂/yr (Figure 95), the majority of which use CO₂ in enhanced oil recovery (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 4.1MtCO₂/yr to the current annual injection rate. Most of that CO₂ is also slated for EOR.

Figure 95: 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.

Still, CCS deployment in the US has encountered serious difficulties, with high-profile projects failing to secure key permits, being frustrated by insufficient regulatory frameworks regarding subsurface ownership, or facing long-term liability issues related to cost overruns during construction. On paper, at least, projects that can utilize the CO₂ in some productive manner (EOR, industrial processes) have a higher chance of success, but only somewhat. CO₂ sales alone are 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.

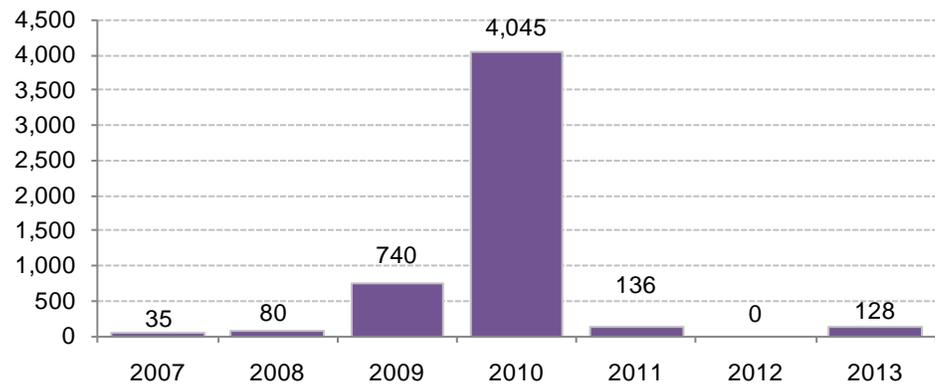
The largest, most advanced project in the US is Mississippi Power Kemper, a 582MW (net) integrated gasification combined-cycle plant. About 65% of the plant's CO₂ emissions are planned to be captured, transported via a 60-mile pipeline, and sold on a long-term contract to an existing EOR company in the state. Mississippi Power is expecting to complete plant construction in 2014 but the project has faced many challenges, including strong opposition from environmental groups and serious cost overruns. The Mississippi Public Service Commission (MPSC) is currently conducting a 'prudence review' of public financial support for the project and could conclude that the company must bear the entire cost of the project, which would represent a massive setback. The latest cost estimates for the power and CCS components of Kemper are \$3.9bn, while cost recovery from ratepayers is capped at \$2.9bn. If the plant fails to start operating by end of May 2014, it will forfeit \$133m in investment tax credits.

Despite these difficulties, Kemper is expected to start operating in 2014. While its difficult development path may make other state public utility commissions wary of supporting CCS through rate recovery, its problems will not necessarily impair the rest of the industry's development.

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 \$4bn (Figure 96). Most of the 2010 spending was for Mississippi Power Kemper. The \$3.9bn project is supported in part by a \$270m DOE grant.

While investment activity dropped in 2012 and 2013, one large-scale US project is slated to start construction in 2014 – 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 seek approximately \$3bn in asset financing. Already, over \$1bn in support has been pledged by the Chinese Export-Import Bank in 2011. Financing may close in 2014, 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 96: Asset finance for post-financial investment decision 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.

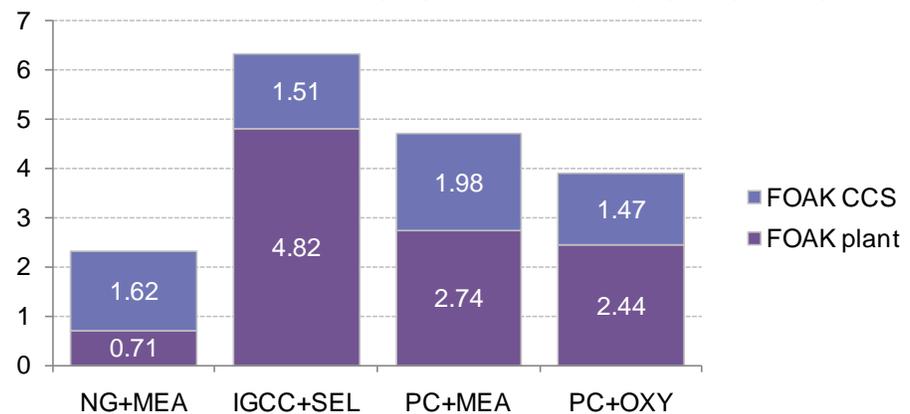
In addition, pre-FID projects in Texas, Louisiana and Wyoming may have low-cost funds available from tax-exempt bond issuances. Developers of three US projects have tapped into federal or county bonds for infrastructure development. For example, NRG Energy secured \$54m in tax-exempt bonds, part of which 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 include 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 those that are likely achievable once these technologies are deployed extensively, in the order of tens of gigawatts).

Figure 97 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 97: Estimated first-of-a-kind (FOAK) capital cost for CCS projects (\$/MW)



Source: Bloomberg New Energy Finance Note: Costs based on 250MWe base plant and capture. 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 CO₂ 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 CO₂ to the EOR industry. Non-grant-supported projects are exclusively those capturing or separating CO₂ to sell for EOR.

About 70% of CO₂ used for EOR comes from natural sources, and as oil prices – and CO₂ demand – have climbed in recent years, anthropogenic CO₂ supplies have also increased. The main anthropogenic CO₂ source is from natural gas processing plants which already supply about 13MtCO₂/yr. Planned expansions at gas processing plants along with CO₂ capture from power and industrial sources could add 10MtCO₂/yr by 2016, which may not be enough to meet demand.

The price of CO₂ for EOR is currently in the range of about \$20-40/tCO₂. At those prices, CO₂ 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 CO₂ capture economics.

SECTION 6. DEMAND-SIDE ENERGY EFFICIENCY

No less than 26 states now have utility efficiency standards on the books and other state- and federal-level policies supporting energy efficiency are under development. This includes legislation that would allow efficiency improvements to be paid through property tax bills and rules requiring buildings to achieve energy efficiency benchmarks or to disclose energy consumption.

Energy intensity in key industrial sectors has been falling. While industrial manufacturing output slipped 3% from 2002-10, energy consumption plummeted 17%. Buildings have offered a different story, however with energy intensity rising, likely due to the higher number of electricity-consuming appliances contained within them. Certification schemes provide an alternative metric for the deployment of energy efficiency in buildings; the rate of Energy Star certification has accelerated since the mid-2000s to the point that over 3bn square feet of floor space is now covered.

The age of intelligent homes and a more intelligent grid is on the horizon. Some 53m smart meters have been deployed in the US, though the pace of deployment is slowing. Other investment areas in the smart grid industry include distribution automation, home area networks, and smart grid analytics software.

Demand response, a temporary load reduction which allows power consumers to cut their energy costs and utilities to scale back production from some of the costliest power plants, is now a 28GW market nationally.

6.1. Energy efficiency

Policy

Energy efficiency policies can come at the federal or state level and in many forms. Examined in this section are policies that have been among the most significant for the sector, including mandates on utilities, standards for appliances and the thermal performance of buildings, and policies allowing energy efficiency deployment to be paid through property tax bills. The federal government can make its mark on the market in one further notable manner – by procuring energy efficiency services through performance contracts.

Policies for utilities: energy efficiency legislation

From 2006 to 2011 annual US utility budgets for energy efficiency grew from \$1.9bn to \$7.1bn, as estimated by the American Council for an Energy-Efficient Economy (ACEEE). This represented sustained annual growth of over 30% over the course of five years. However, the most recent figures suggest that this is now slowing, with ACEEE estimates putting 2012 utility budgets at \$7.2bn, a growth of just 2% from 2011. The slowing growth can be attributed to a decrease in the rate of adoption of the state-level policies to support utility investment in end-user energy efficiency and increasing cost-effectiveness of existing programs.

Figure 98: US states by type of electricity policy for decoupling, 2000-13 (number of states)

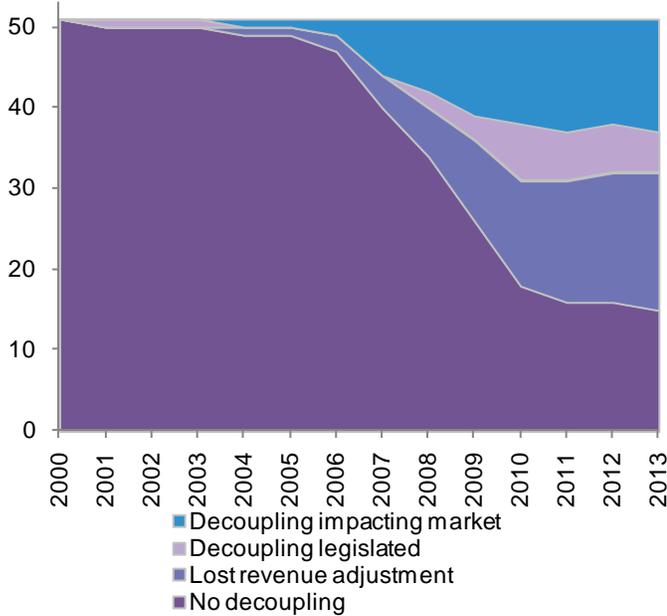
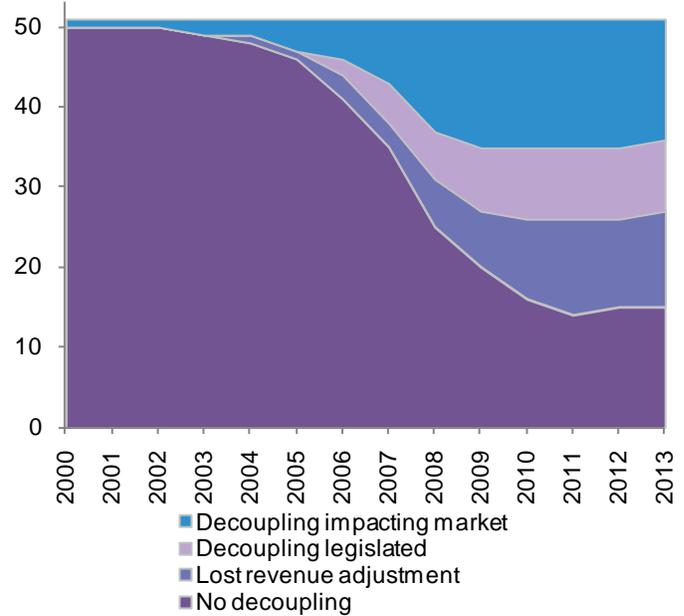


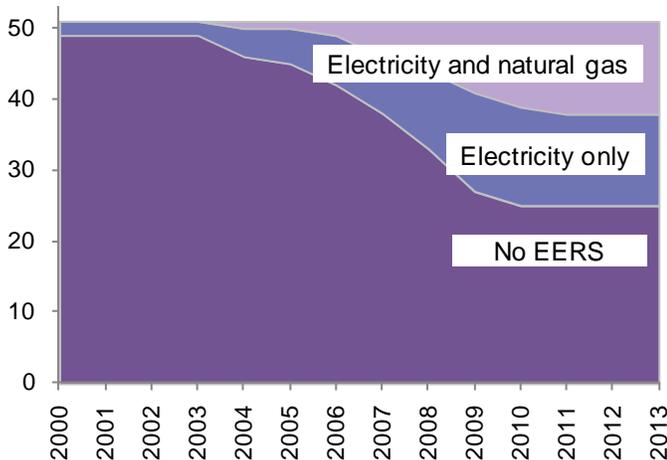
Figure 99: US states by type of natural gas policy for decoupling, 2000-13 (number of states)



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

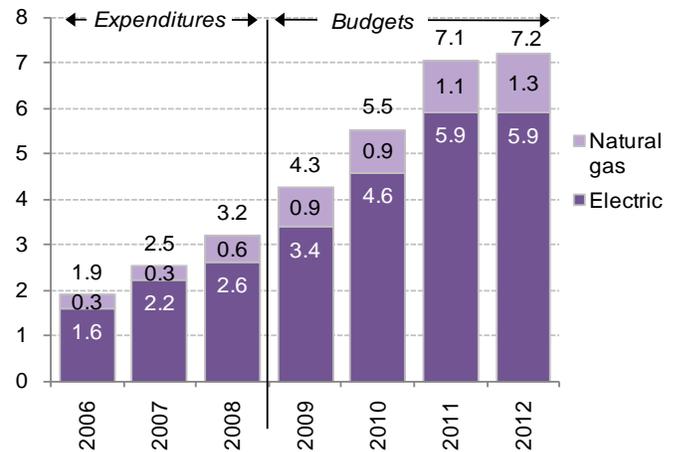
This trend is illustrated in Figure 98 and Figure 100, which show the uptake of decoupling and Energy Efficiency Resource Standards (EERS) in US states. Decoupling refers to regulatory frameworks for setting rates wherein a utility's revenues are decoupled from the volume of kWh that they sell, removing 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); at present, 26 states have EERS for electricity or for both electricity and 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.

Figure 100: US states adopting EERS, 2000-13 (number of states)



Source: ACEEE, DSIRE, Bloomberg New Energy Finance

Figure 101: Utility energy efficiency spending and budgets, 2006-12 (\$bn)



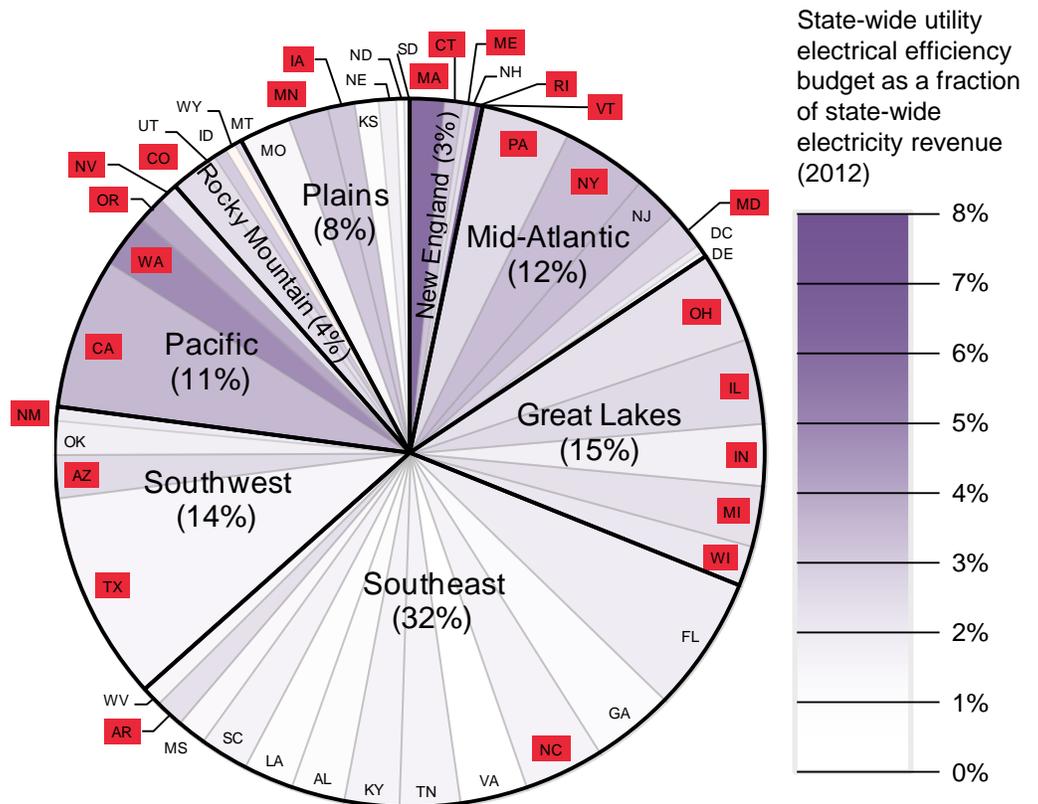
Source: 2012 American Council for an Energy-Efficient Economy.

Reprinted with permission. www.aceee.org. Note: Figures for 2006-08 represent expenditure, 2009-12 represent budget.

As the figures show, both decoupling and EERS were introduced by a large number of states between 2006 and 2010, but since then there have been relatively few new states announcing legislation for either. The growth of utility investment in energy efficiency during that period was driven by new states' decoupling and EERS programs. The slowing growth of budgets in the most recent period captured, 2012, may be attributable to factors such as more cost-effective energy efficiency programs and the growth of alternative channels for energy efficiency investment. For the states with EERS, many are still in the process of ramping up their programs to reach even more stringent targets.

Policy trends and utility spending follow a distinctly regional pattern, as illustrated in Figure 102. The majority of states in the Pacific, Mid-Atlantic, and New England regions have adopted EERS legislation and it is in these regions where levels of utility spending on energy efficiency are highest. By contrast the Southeast, which accounts for 32% of US electricity consumption, has only two states with EERS laws. Mississippi and Louisiana did make major headway in energy efficiency programs in 2013 though not on an EERS. Still, these programs are perceived to be an important step in the direction of promoting energy efficiency. There is therefore considerable potential for growth in utility spending on energy efficiency in the Southeast – whether or not that potential can be fulfilled depends on the region's state policy-makers.

Figure 102: Share of total electricity consumption by US state, by region, 2012



Source: ACEEE, EIA, Bloomberg New Energy Finance. Note: The shading for individual states indicates the budget for energy efficiency programs as a fraction of utility revenue. States highlighted in red have EERS requirements for electric utilities. Hawaii and Alaska not depicted.

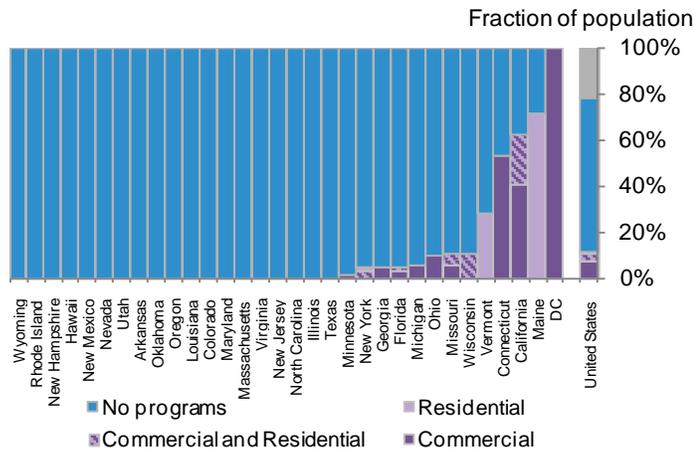
Policies for financing: PACE

Property-assessed clean energy (PACE) is a financing framework for energy efficiency that enables loans used for energy upgrades to a building to be repaid through the property tax bill. The rationale for such an arrangement is that it effectively attaches the debt to the building rather than the building owner, sidestepping some of the agency issues associated with funding retrofits as well as reducing risk for lenders. (The following paragraphs discuss the policy aspects of PACE; a section further below, under 'Financing', assesses the financial impact.)

Because PACE is repaid through property tax it is only available where local government has chosen to implement a scheme. This in itself is only possible where the state government has passed enabling legislation. It is therefore only once both state and local governments have opted in that the market can grow. At present 31 states, plus Washington DC, representing 77% of the US population, have PACE-enabling legislation. However only three of those states (Maine, California and Connecticut) and Washington DC have PACE financing available in more than half of local jurisdictions (weighted by population). As of July 2013 the total population of local US jurisdictions in which PACE financing is available in one form or another stood at 35m, 11% of the country's population.

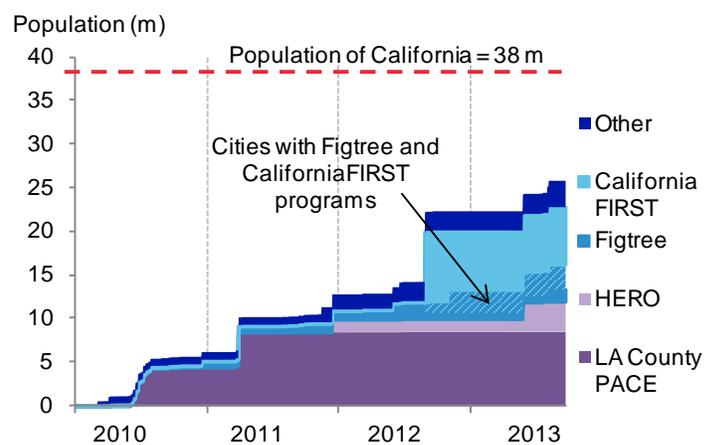
Despite legal difficulties, PACE has successfully negotiated the first hurdle toward broader adoption – acceptance from state governments. The current bottleneck is the adoption of PACE among local governments. Once that is passed the success or failure of PACE lies in the hands of the market.

Figure 103: Availability of PACE financing by US sector and state, as of July 2013



Source: PACENow, CaliforniaFIRST, Clean Energy Sacramento, Figtree Energy Financing, GreenFinanceSF, Renovate America, LA County PACE Program, CEFIA, YGreene, Florida PACE Funding Agency, Lean and Green Michigan, Energize New York, ONOED, Better Buildings NW Ohio, Efficiency Vermont. Note: Only states with enabling legislation are shown.

Figure 104: Propagation of PACE programs in California cities and counties, 2010- July 2013 (by population size)

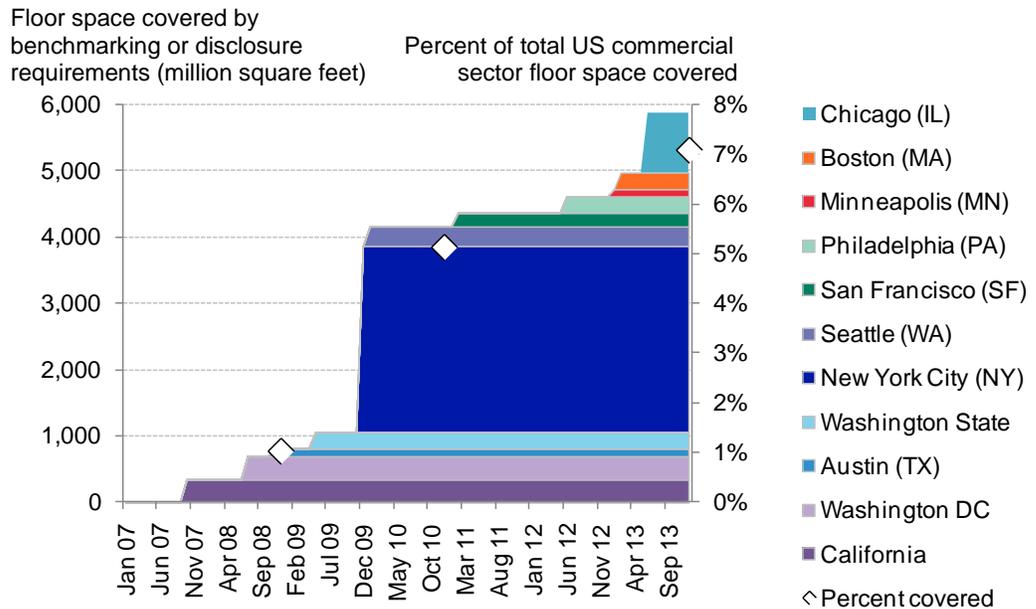


Source: LA County PACE, HERO, Figtree, CaliforniaFIRST, PACENow, Sonoma County Energy Independence Program, Bloomberg New Energy Finance.

Policies for buildings and appliances

Over the past six years, jurisdictions at the state and city levels have established policies around building energy use. These policies can include requiring buildings to achieve certain energy efficiency benchmarks or mandating that buildings disclose their energy consumption. Through 2013, 5.8bn square feet of commercial floor space, or an estimated 7% of total US commercial sector floor space, was covered under these kinds of policies (Figure 105).

Figure 105: US building floor space covered under state or local building benchmarking / disclosure policies, 2007-13

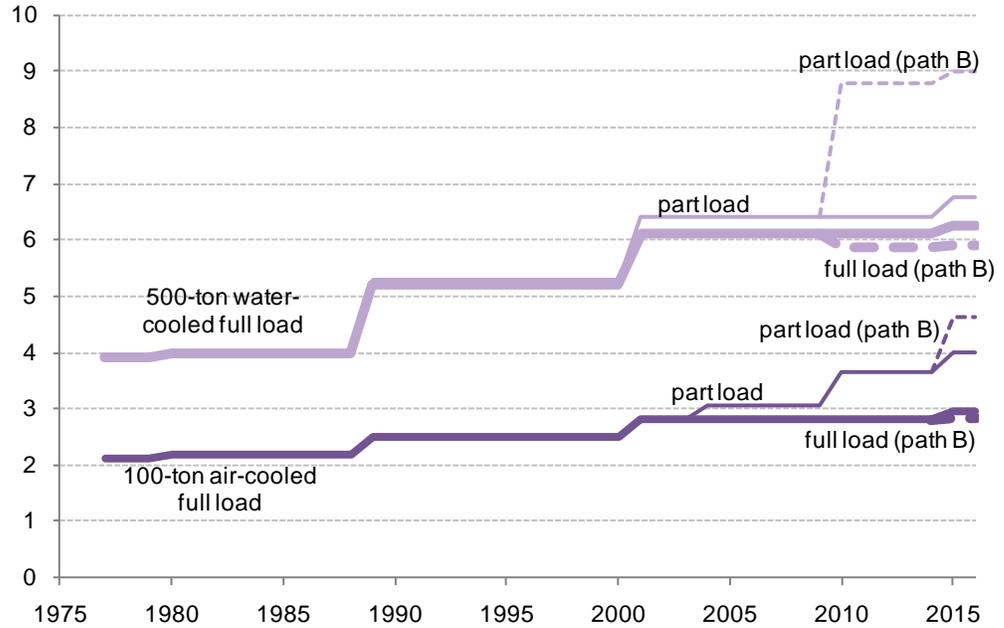


Sources: Institute for Market Transformation; US DOE, Buildings Energy Data Book; Bloomberg New Energy Finance Note: Accounts for overlap between cities and states (eg, no double-counting between Seattle and Washington State numbers). Assumes that DOE Buildings Energy Data Book definition of ‘commercial sector’ at least roughly corresponds to IMT’s definition. Shaded areas show amount of floor space covered, diamonds represent percent of US commercial sector floor space covered. Diamonds are spaced out in irregular intervals since data about the denominator (total commercial sector floor space in the US) is available at irregular periods (2008, 2010, 2015); the diamond for December 2013 assumes linear growth in denominator over 2010-15.

Appliance standards play an important role in both the deployment of efficient hardware and the improvement of technologies over the course of time. Figure 106 shows how ASHRAE¹⁹ Standard 90 for chillers has evolved since the late 1970s in terms of coefficient of performance. The graph illustrates not only the improvements in efficiency required by the standard, but the increasing level of nuance: in the early 2000s the standards began to require that systems exhibit a higher coefficient of performance when operating at partial load. Since 2010, provision has been made within the standards to recognize the different usage profiles for systems. In the case of “Path B” (as marked on the chart) systems can have a lower coefficient of performance at full load, so long as their partial load coefficient of performance is substantially higher – reflecting a different requirement for systems which will be operating primarily at part-load conditions.

19 Formerly the American Society of Heating, Refrigerating and Air Conditioning Engineers

Figure 106: Stringency of ASHRAE Standard 90 in terms of chiller performance, 1977-2016 (coefficient of performance)



Sources: ASHRAE 90.1-2013 Standard

Thermal performance – ie, building insulation – is also critical for building energy profiles, and here too the standards have consistently increased. Figure 107 and Figure 108 show the rise in performance standards by 'thermal component placement' (location in the building where the insulating material is placed, such as roofs and walls).

Figure 107: Thermal performance standards by building placement for residential buildings (R-values)

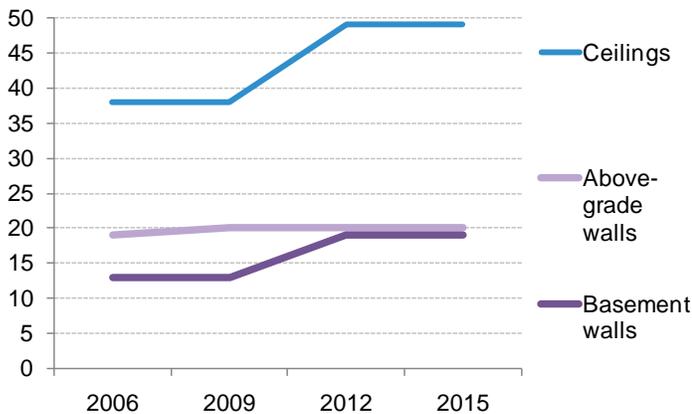
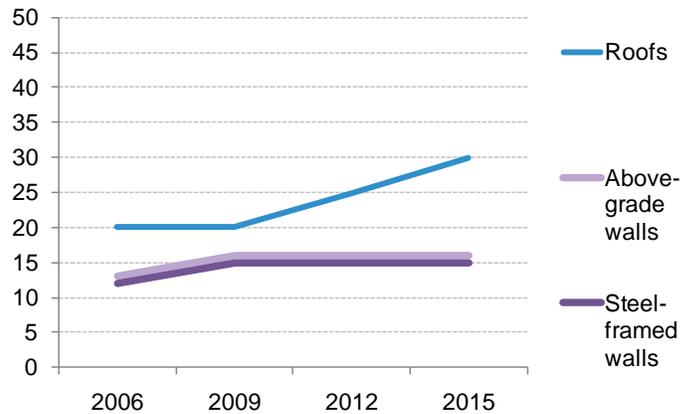


Figure 108: Thermal performance standards by building placement for commercial buildings (R-values)



Source: PIMA (Polyisocyanurate Insulation Manufacturers Association), NAIMA (North American Insulation Manufacturers Association), based on standards from ASHRAE and IECC; Bloomberg New Energy Finance Notes: 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).

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 IECC²⁰ standards depicted above, has increased dramatically in the past five years. According to the 2011 Annual Report of the

20 IECC is the International Energy Conservation Code.

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 walls and roofs by over 50% in many parts of the country; in others they will be doubled from 2007 baseline requirements.

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.

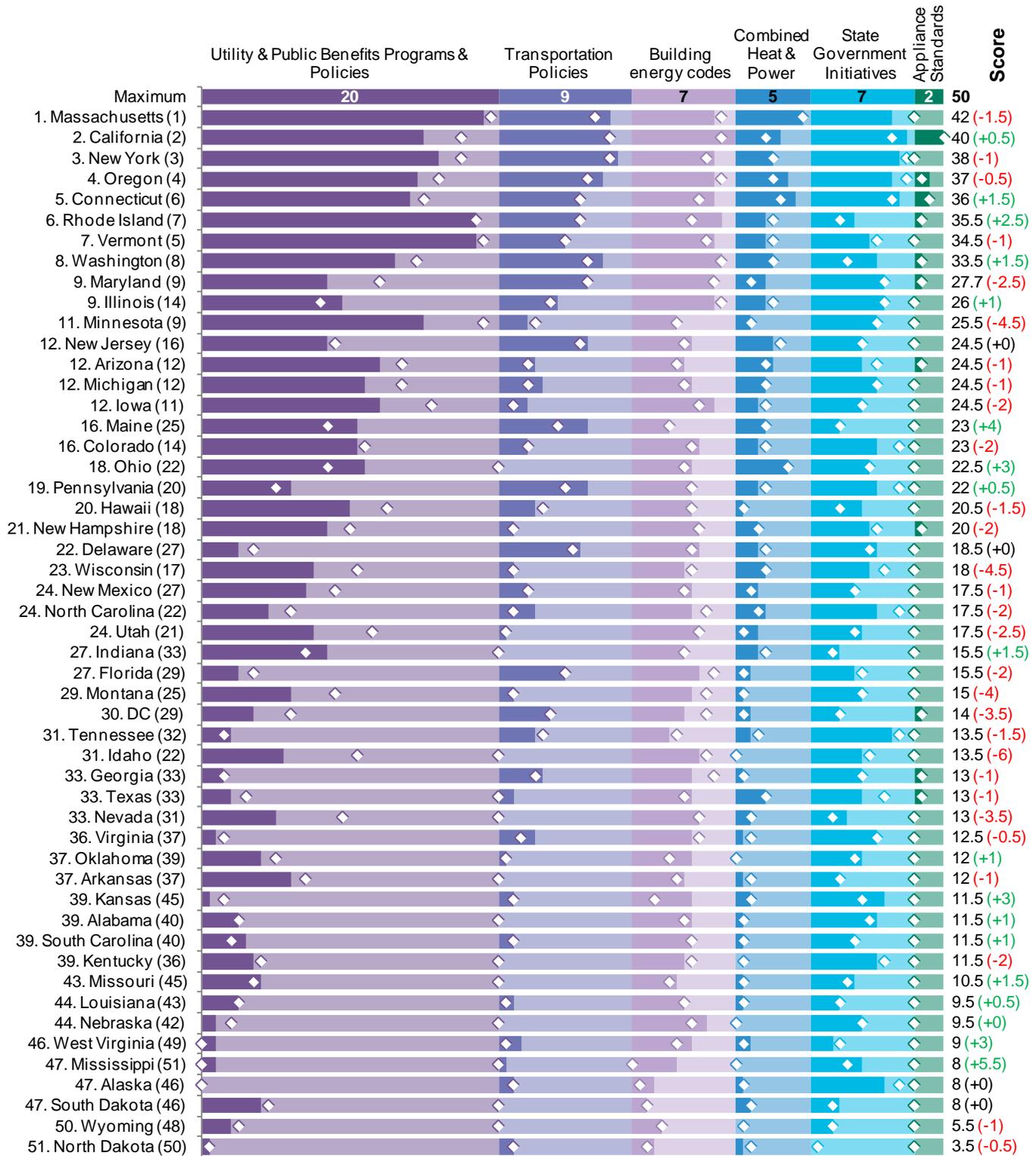
Policy comparison: US states’ efficiency policies

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 109.

The top four states remain unchanged, with Massachusetts, California, New York and Oregon leading the way (in that order). Connecticut makes it into the top five due to improvements in building energy codes and combined heat and power policy, at the expense of Vermont which dropped to seventh due to slower progress on state government initiatives and combined heat and power.

The most improved states were Maine, which gained on utility and public benefits programs and transportation policies, and Mississippi which climbed from the bottom of the table thanks largely to new building energy codes.

Figure 109: ACEEE state-by-state scorecard for energy efficiency policies, 2013



Source: Bloomberg New Energy Finance, ACEEE. Note: Brackets indicate 2012 ranking and change in score. Diamond symbols indicate 2012 score within a particular category. ACEEE adjusts their methodology each year for the Scorecard to reflect the changing policy environment; this accounts for the dip that many state scores took in the 'Utility' category.

Policy: procurement of energy efficiency at federal facilities

The federal government represents one of the most important customers for US energy service companies (ESCOs) due to the large size of their facilities and their relatively long-term outlook. However the market can also be fairly 'lumpy' due to the large size of the projects and, more importantly, the influence of government policy. (Figure 118, further down in the report, shows ESCO investment activity across all sectors – not just federal government. That analysis shows that ESCO financing broadly has been steadily increasing.)

Figure 110 and Figure 111 show developments in the market for federal Energy-Saving Performance Contracts (ESPC). There was a significant peak in the market in 2009, due in part to the impact of stimulus money set aside for energy efficiency. However since 2011 the federal market has been relatively slow, suggesting that during the peak period projects were being brought forward in order to take advantage of stimulus-related opportunities.

At the end of December 2011, President Obama issued a memorandum instructing federal agencies to enter into \$2bn of energy performance contracts during 2012 and 2013. In December 2013, the administration announced that federal agencies had developed a pipeline of about \$2.3bn in projects, an increase of more than 200% per year compared with the levels before the two-year initiative. Of that pipeline, approximately half was under awarded contracts and the balance of contracts was pending award. To continue this federal ESPC activity, in December 2013, the administration expanded its initiative through 2016 and instructed agencies to work with the DOE in early 2014 to identify an expanded pipeline of additional commitments for energy financed projects.

Figure 110: Number of federal ESPCs executed through the DOE's umbrella agreement, 1998-2013

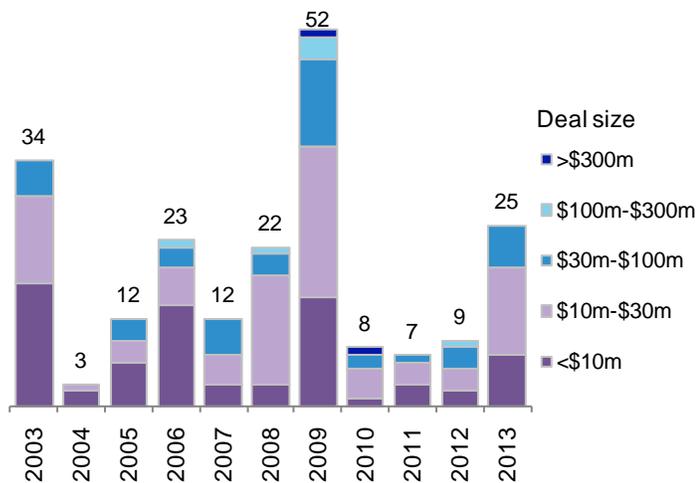
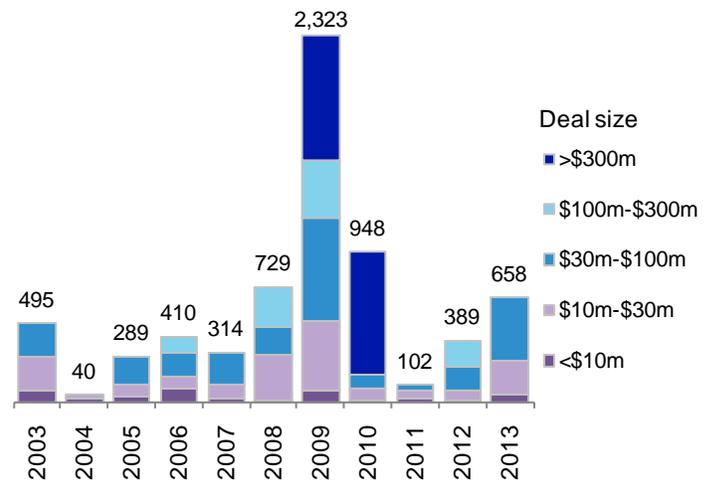


Figure 111: Contract value of federal ESPCs executed through the DOE's umbrella agreement, 1998-2013 (\$m)

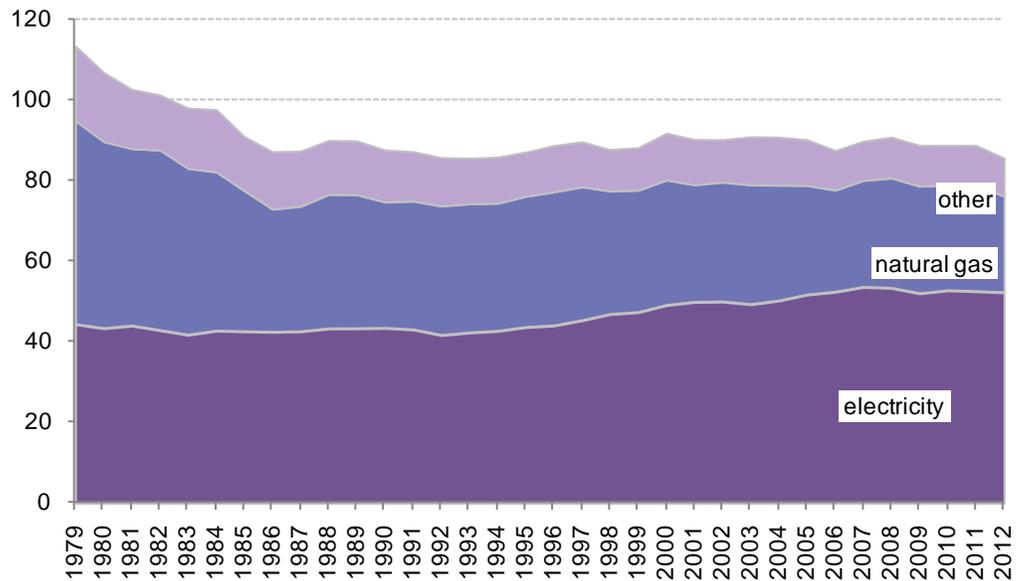


Source: FEMP/DOE, Bloomberg New Energy Finance. Note: DOE's umbrella agreement refers to indefinite-delivery, indefinite-quantity (IDIQ) contracts between the DOE and energy service companies. Totals are summed in terms of calendar years in order to facilitate comparison with government targets, whereas DOE sources commonly sum over fiscal years.

Deployment – building efficiency

The impact of efficiency deployments can be seen in terms of energy consumption within buildings. Figure 112 shows how the energy consumption of commercial buildings in the US has evolved since the 1979. The chart shows energy intensity, which in this case means energy consumed per unit of building space.

Figure 112: US commercial building energy intensity, 1980-2012 (kBtu/ft²)



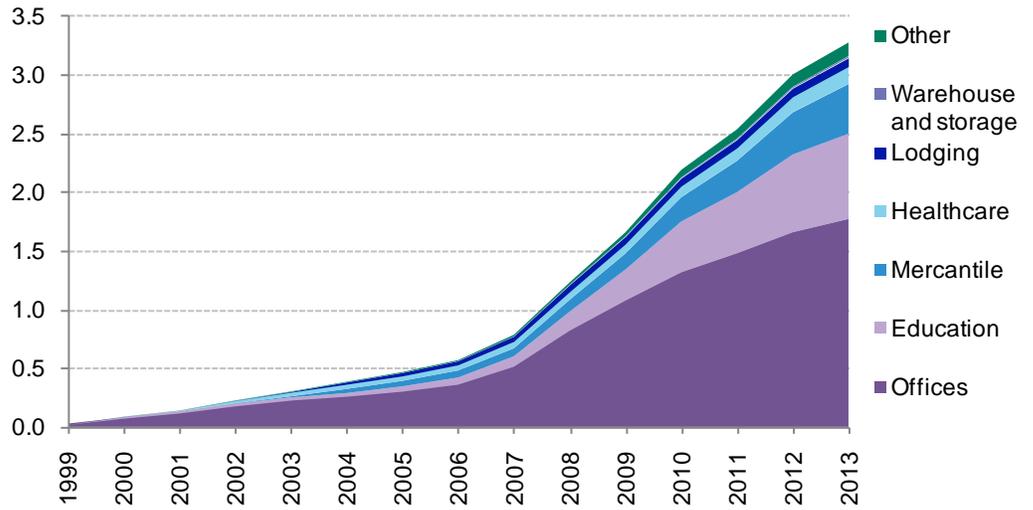
Source: EIA, Bloomberg New Energy Finance Note: This analysis is based on (i) EIA data on US commercial building energy consumption and floor space for the years 1979, 1983, 1986, 1989, 1992, 1995, 1999, 2003 and (ii) EIA data for total US commercial sector energy consumption for every year between 1979-2011.

While there has been a significant reduction in commercial building energy intensity, most of this occurred between 1979 and 1987 and was driven mainly by reduced natural gas consumption, which itself was most likely a reflection in increased prices. Moreover the electricity intensity of buildings has increased overall, particularly from 1992, likely owing to a rise in the number of electricity-consuming appliances within modern buildings.

Whether or not buildings and their constituent appliances have become more energy efficient is difficult to determine, since this contribution to energy intensity cannot be separated from the effect of the increased uptake in electricity-consuming appliances. This exposes the limitation of energy intensity as a metric for energy efficiency.

Certification schemes provide an alternative metric for the deployment of energy efficiency – it can be assumed that in order to achieve improved certification, additional measures must be taken within a building. For this a building must first be certified. Figure 113 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 square feet of floor space is now covered.

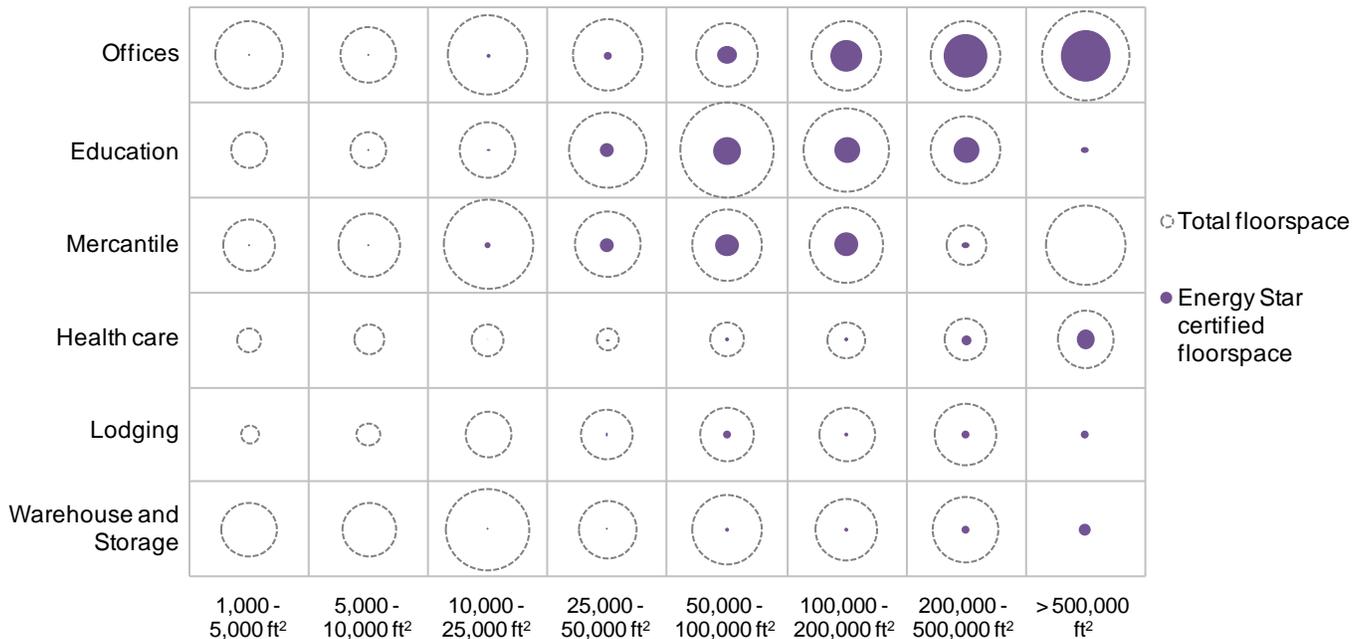
Figure 113: Energy Star-certified floor space in US non-residential buildings, categorized by usage, 1999-2013 (bn ft² of floor space)



Source: US EPA, Bloomberg New Energy Finance

While the growth of the rate of certification is impressive, it is likely to slow. As can be seen, the bulk of the growth has been driven in offices, where the rate of certification is now slowing down. This is due to the fact that a significant proportion of larger offices are now certified (as seen in Figure 114), meaning there are fewer easy opportunities. If certification is to continue to grow, it will need to be in segments where the current rate is low. This includes sectors such as warehouses and storage, and buildings below 50,000 square foot (in which rates of certification are low across all sectors).

Figure 114: Energy Star-certified floor space and total floors space for US commercial buildings, segmented by sector and building size, December 2013

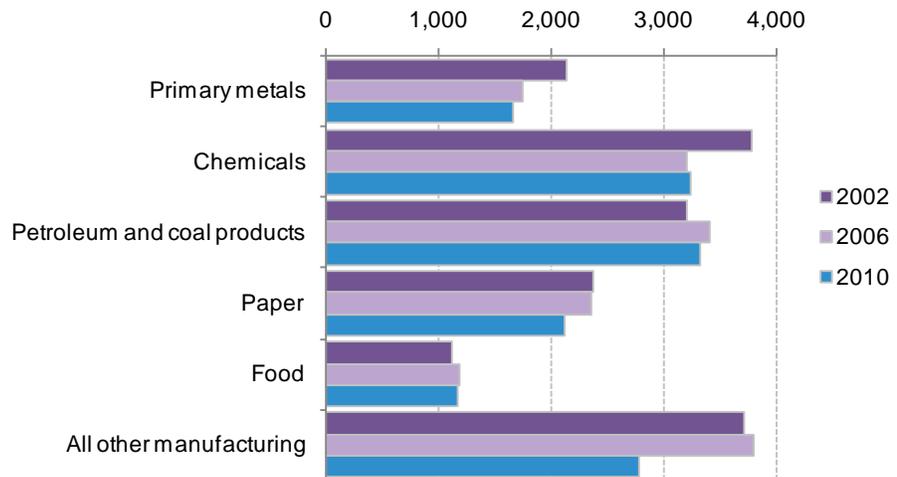


Source: US EPA, EIA, Bloomberg New Energy Finance. Note that data is lacking for total US floor space of warehouses, lodging and educational buildings with floor space in excess of 500,000ft².

Deployment – industrial efficiency

US industry is becoming more efficient in its consumption of energy. Over the 2002-10 period, manufacturing gross output fell by 3% while total energy consumption fell by 17%, based on data gathered in the EIA’s quadrennial Manufacturing Energy Consumption Survey (MECS). Energy consumption comes in two forms: as a fuel and as a feedstock. Figure 115 shows fuel consumption for the five most energy-intensive sectors (plus all others grouped into one sector). Only the petroleum and coal products sector, and the food sector, saw an increase in fuel consumption. In the case of petroleum and coal, fuel consumption (4% growth) outpaced gross output (3% growth); in the case of the food industry, the opposite was true (4% fuel growth against 5% output growth).

Figure 115: US manufacturing consumption of energy as a fuel, 2002-10 (trillion Btu)



Source: EIA Manufacturing Energy Consumption Survey, Bloomberg New Energy Finance

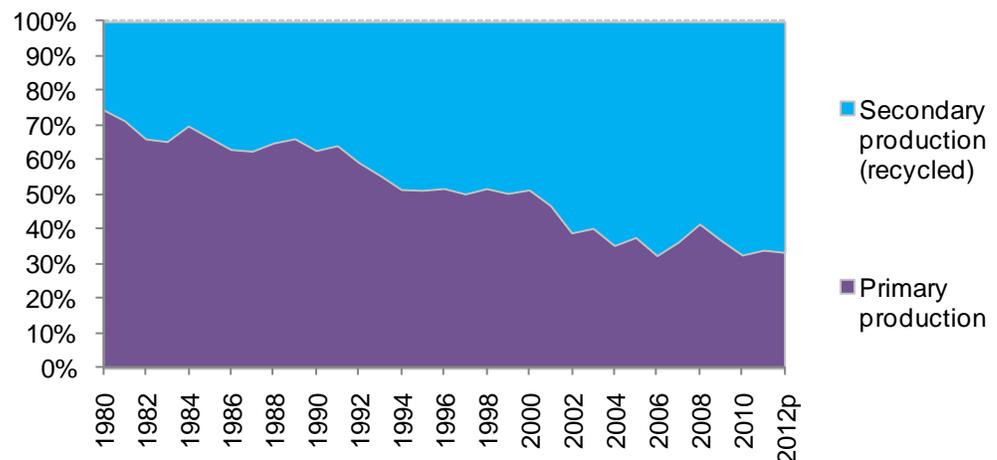
US aluminum serves as a useful case study to evaluate deployment of efficiency in the industrial sector. Aluminum production requires more electricity than any other manufactured product; the US aluminum industry is responsible for 1.2% of all electricity consumed in the country.²¹ Recycling and the efficient use of produced aluminum can thus result in significant energy savings.

Recovery from scrap metal consumes just 8% as much energy as producing new aluminum.²² This ultimately improves the lifecycle sustainability and lowers energy intensity of aluminum products, and goods made with those products. Driven by the economic benefit of recycling, 66% of all aluminum produced in the US in 2012 originated from ‘secondary’ sources – ie, two-thirds of new aluminum came from recycled post-consumer and industrial scrap.

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

22 This ratio was previously lower (ie, recovery from scrap metal used to consume even less than 8% as much energy as producing new aluminum), but the energy intensity for making primary aluminum has declined in recent years.

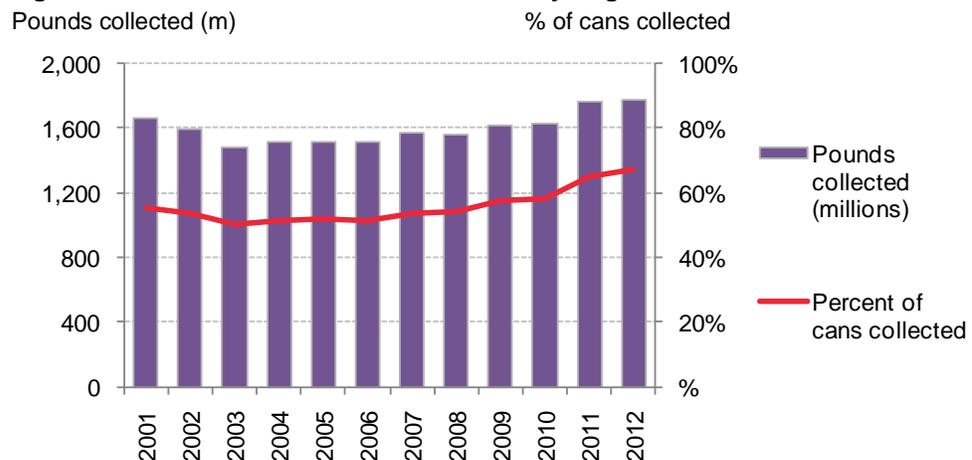
Figure 116: US production of primary vs secondary aluminum, 1980-2012p



Source: Bloomberg New Energy Finance, US Geological Survey Notes: 2012 data are preliminary (2012p), and are thus subject to revision. Not shown here is the considerable share of aluminum imports consumed in the US. Historically, imports have met ~40% of US aluminum demand.

Aluminum recycling has also been increasing, driven largely by the addition of imported cans into the US recycling stream, according to the Aluminum Association. In 2012, 67% of aluminum cans produced were recycled, up from 50% in 2003 (Figure 117).

Figure 117: 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

Financing: investment through formal frameworks (ESCOs and utility programs)

Investments in energy efficiency come in all shapes and sizes, from the billion-dollar army base retrofit to the trip to the hardware store to pick up a new light bulb. Of principal interest, however, are those investments, whether large or small, that occur through frameworks that specifically leverage the value of energy efficiency.

These fall into two main categories. First, there are investments in energy efficiency made by energy suppliers, usually in order to comply with requirements such as EERS. Secondly there are

investments driven principally by the energy consumer, mainly driven by the economic benefits of reduced energy consumption. This is the segment that ESCOs are typically used to serving.

There are many smaller investments in energy efficiency that fall outside of utility programs and ESCO activity and although these no doubt sum to a significant volume of investment, the usefulness in tracking them is doubtful – putting a figure on this activity does not change the fact that it is fragmented and disparate. Therefore the data in Figure 118 do not represent all investment in energy efficiency in the US, but it does represent all investment in energy efficiency in the US through formal frameworks (either utility programs or ESCO business models) and as such the majority of investment that it is useful to know about.

Since the 1990s there has been significant growth in investment through these frameworks. From the early 1990s to the mid-2000s this was driven principally by the growth of the ESCO sector and in particular the energy-saving performance contracting (ESPC) business model. ESCO revenues (which correspond to investments in energy efficiency through ESCOs) were \$5.2bn in 2011 and may have been around \$6.6bn in 2013, according to the Lawrence Berkeley National Laboratory, which compiles the investment data from companies. Since the mid-2000s the majority of growth was due to utility programs, driven by state-level EERS legislation (as already discussed). Together, the ESCO and utility programs saw around \$12bn of investment in 2012 (Figure 118).

Figure 118: Investment in energy efficiency through ESCOs and utility programs, categorized by program, 1993-2012 (\$bn)

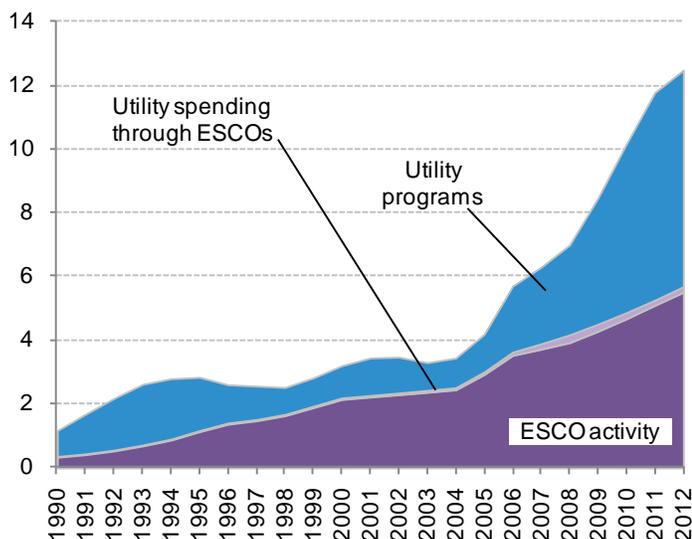
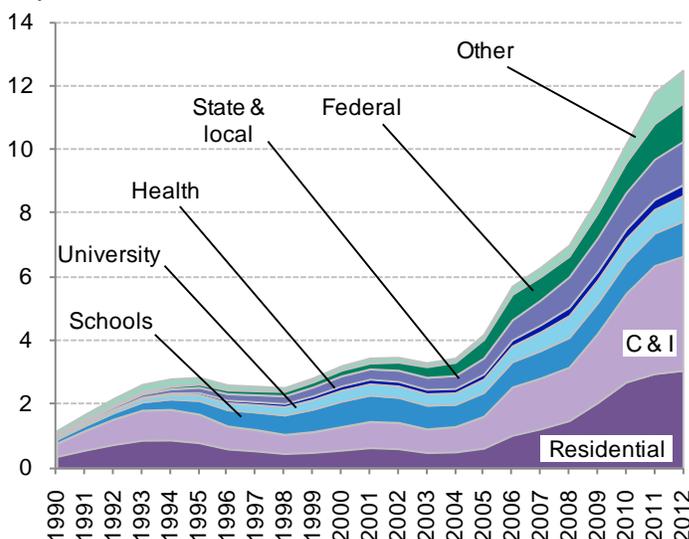


Figure 119: Investment in energy efficiency through ESCOs and utility programs, characterized by end-user, 1993-2012 (\$bn)



Source: Lawrence Berkeley National Laboratory, Stuart et al, “Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry”, September 2013; NAESCO; EERE; ACEEE; CEE; EIA; Bloomberg New Energy Finance. Note: ‘C& I’ refers to the commercial and industrial sectors. “State & local” refers to state and local government facilities.

Figure 119 shows how these formal investments break down between sectors. Generally speaking almost all of the investment in residential energy efficiency comes through utility programs, though this may change if financing schemes such as PACE are able to gain traction. All of the investment in the municipal, universities, schools and hospitals (MUSH) segment comes through ESCOs. The bulk of formal investment into commercial and industrial energy efficiency happens through utility programs. However this is an area where ESCOs are currently looking to increase their penetration.

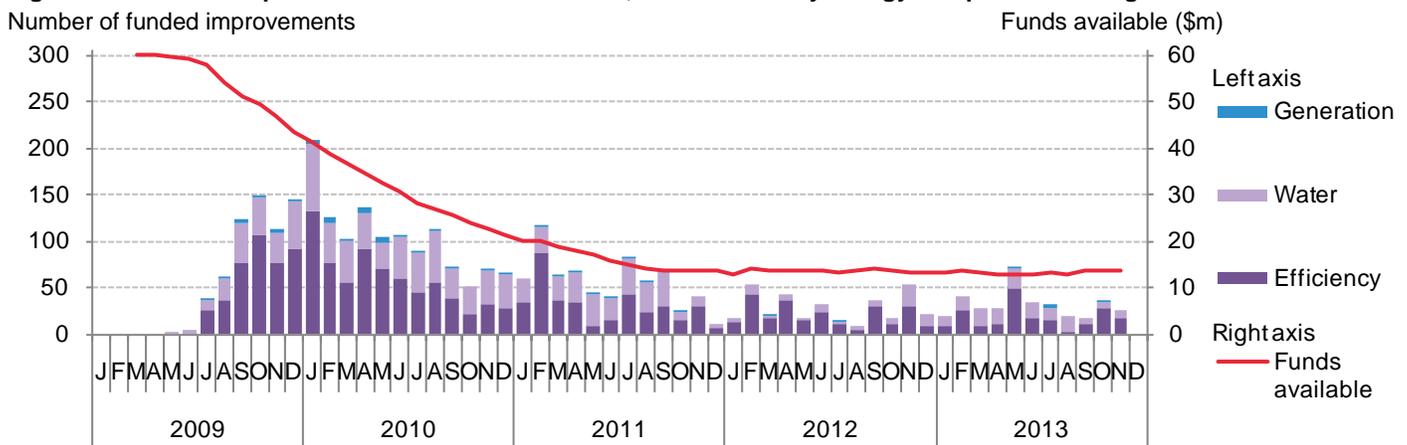
Financing: other frameworks (PACE)

If the ESCO sector is to achieve significant success within the commercial building segment, a suitable financing model (or several suitable financing models) will be necessary. The sector is challenging for a variety of reasons, including agency issues, short-term horizons for building use, and the balance-sheet impact of efficiency investments.

As noted earlier, policy-makers have a role to play in creating the legislative frameworks to support investment in energy efficiency. PACE is one such framework and, as discussed, the current bottleneck to its broader adoption is uptake among local jurisdictions. Beyond that the challenge lies in gaining market acceptance and there is scarce information on existing programs.

One exception to this is the Sonoma County Energy Independence Program, which publishes details on both activity levels and available funding. Since the program's inception \$64m of contracts have been funded, which, for a jurisdiction with a population of 490,000, is an encouraging result. However it remains to be seen if such success can be replicated elsewhere.

Figure 120: Funded improvements and funds available, Sonoma County Energy Independence Program



Source: Sonoma County Energy Independence Program, Bloomberg New Energy Finance

Other financing frameworks that may offer promise for energy efficiency deployment include on-bill repayment and efficiency services agreements – a framework through which guaranteed savings retrofits are funded by a third party which then bills the customer for measured and verified energy savings at an agreed price.

Economics

Figure 121 and Figure 122 show the results of an analysis of the cost per kWh of energy saved across 282 federal ESPC contracts. In most cases the cost of saving energy is either less than or similar to the cost of the energy being saved, reflecting the cost-effectiveness of energy efficiency. However there are two points worth exploring:

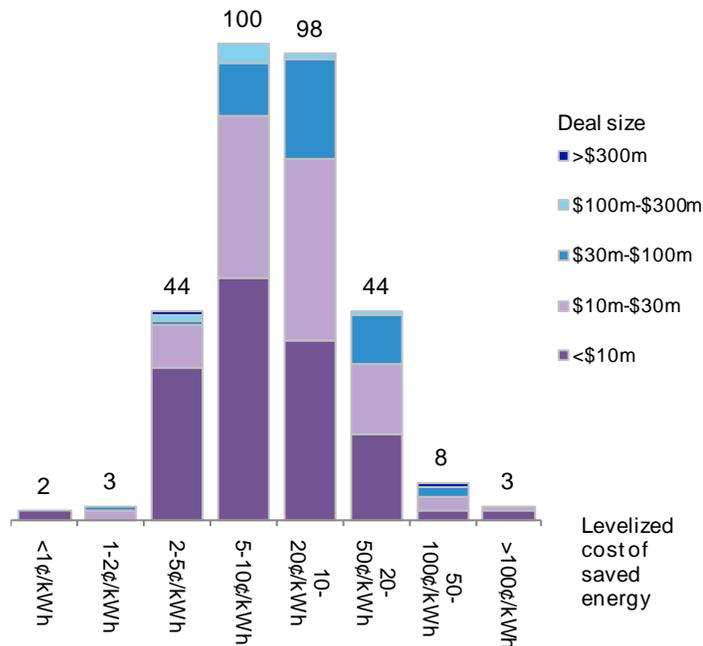
- There is a large range in the implied cost of energy savings.
- There is a significant number of contracts where the cost of saving energy is above \$0.20/kWh, which in most scenarios is not cost effective.

Regarding the first of these, there is very little in common between two projects and the economics of saving energy varies significantly, depending on factors such as: the initial state of the building or facility where the project is taking place; the types of measure being installed; the future usage of the

building or facility; local conditions (eg, weather). The cost of energy efficiency therefore depends entirely on the particular circumstances and there is little value in comparing one project to another.

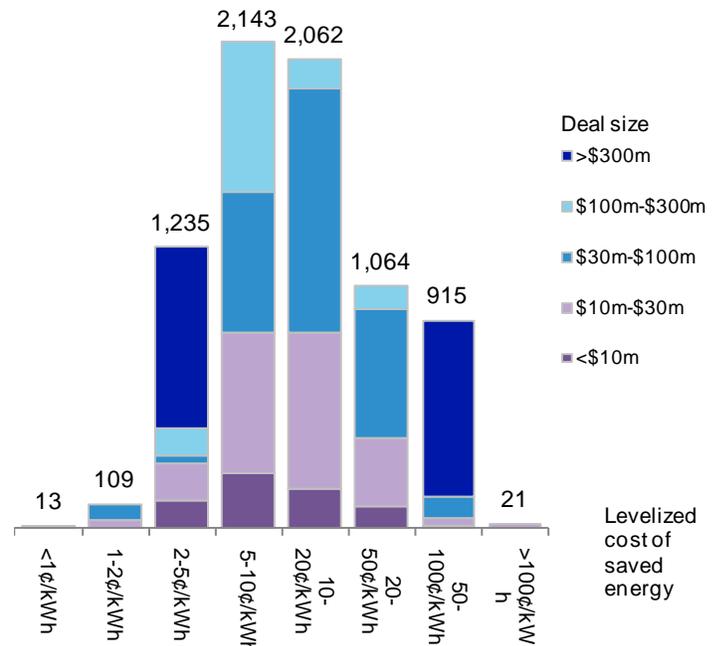
Regarding the second of these points, it is worth noting that energy efficiency is not always an end in itself, but a means to an end. In the case of an ESPC, the objective may be to reduce energy expenditure cost-effectively, but it may also be to refurbish a facility or install renewable and/or onsite generation for reasons such as resilience or to meet environmental goals. In those latter cases energy savings are frequently used to pay for the refurbishment, or the ESPC contract structure may be a convenient framework through which to install generation alongside other measures. In such cases the cost per kWh saved will not differ greatly from local energy prices – but that is because the scope of the project goes beyond achieving energy savings in the most cost-effective way and as such the cost per kWh of energy saved is the wrong metric for assessing their merit.

Figure 121: Number of federal ESPCs executed through the DOE's umbrella agreement, sorted by LCOE savings and deal size, 1998-2013



Source: FEMP, Bloomberg New Energy Finance. Note: LCOE calculated using 5% discount rate.

Figure 122: Total value of federal ESPCs executed through the DOE's umbrella agreement, sorted by LCOE savings and deal size, 1998-2013 (\$m)



Source: FEMP, Bloomberg New Energy Finance. Note: LCOE calculated using 5% discount rate.

Market dynamics

There are several market dynamics at play within the broad domain of energy efficiency.

While the ESPC model is an established (and growing) framework for ESCOs such as Johnson Controls, Ameresco, Honeywell, Noresco, Trane and Chevron Energy Solutions to grow their revenues, particularly within public buildings, these companies are also looking to explore other possibilities. One, as discussed, is to expand into commercial buildings either using an ESPC or an alternate financing model such as PACE. Another is to apply their expertise in performance contracting to other types of project, such as microgrids, where there is an opportunity to meet increasing demand for energy resilience among institutional customers.

The development of risk mitigation and insurance products could also pave the way for more activity that makes use of new financing frameworks. These products, such as Energi's Energy Savings

Warranty, essentially guarantee efficiency project performance, increasing overall participation in new energy projects, particularly from smaller, less capitalized ESCOs.

The past few years have seen a growing trend in the field of “intelligent energy efficiency” in commercial buildings. Key players in the market for Building Energy Management Systems (BEMS) include Johnson Controls, Schneider-Electric, Honeywell, and Siemens. However, the BEMS software market is an area where companies, many of which are small and early-stage, are introducing innovative approaches and business models; these include Retroficiency, FirstFuel, Lucid, Agilis, Building IQ, Trane, and UTC. These companies have various software-based offerings that make use of information provided through BEMS, meter data, and other sources to draw conclusions about energy usage. In some cases this is a remote audit to quickly identify easy opportunities for energy saving; in other cases it provides analysis and optimization of systems. Bloomberg New Energy Finance estimates put the current BEMS market size in the US at roughly \$2bn.

An interesting development within that space is the Panoptix app market place, which allows third parties to sell software to integrate with Johnson Controls BEMSs (Johnson Controls having developed Panoptix in late 2011). This ecosystem approach could allow smaller innovators to quickly gain access to a large market. The success of this approach, and whether other large BEMS providers create similar platforms for their systems, depends on whether innovators are able to create software with value sufficiently compelling to drive broad demand among building occupants.

The growth of utility energy efficiency programs has created a new market for specialist providers of energy efficient products and services. While the aforementioned ESCOs are also active in that market, the new players are more likely to be those with a single product or solution targeted at providing utilities with a low-cost option to meet their obligations. Many of these tend to be smaller in scale and are often operating at a local level, providing “boots on the ground”.

Companies that have targeted the opportunity created by utility-funded energy efficiency include providers of customer engagement platforms such as Tendril, EcoFactor and OPower, which have been successful in selling information-driven services to enable utilities to achieve behavioral energy savings among their residential customers. It remains to be seen if these companies can leverage the increased level of engagement with energy consumers to find new opportunities for energy efficiency business models.

On a similar note, the Green Button Initiative has created an increased level of information access and engagement between energy consumers and third parties, which has also created an opportunity for further innovation in information-based residential energy efficiency. This could include propositions targeted at affecting consumer behavior such as those listed above along with devices that take an automated approach to saving energy (more on the theme of ‘smart homes’ in Section 6.2 below).

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 difference between energy efficiency and demand response is that energy efficiency is a permanent reduction in energy consumption while demand response is a temporary load reduction, typically from several minutes to six hours. In some cases, demand response does not reduce overall electricity consumption but rather shifts it to off-peak times. The consumer whose load is being curtailed is generally offered compensation for this service ('incentive-based'). Another form of demand response (known as 'price-based') involves applying time-varying power prices via smart meters to customers, who can then adjust consumption accordingly throughout the day in response to price signals.

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 and ISOs. This 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 deregulation and restructuring policy allowed demand response products to be offered in a competitive retail market environment. Despite a top-down policy structure defined by FERC, each ISO and regional transmission organization (RTO)²³ has different rules around how demand response resources can enter the market, resulting in a fragmented distribution of demand response capacity throughout the US.

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 interval reading 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 2013, over 53m smart meters were deployed in the US, according to Bloomberg New Energy Finance's project database (Figure 123). The market peaked in 2011, with 13.9m smart meters deployed in that year (driven heavily by federal funding), up from just 3.4m in 2008. The pace of smart meter deployments in the US is slowing as the federal funding that stimulated spending from 2009-13 is largely exhausted; several of the largest utilities have already or are currently deploying smart meters, and untapped market potential is shrinking (ie, penetration is increasing, Figure 124).

23 ISO and RTOs are entities that operate wholesale electricity markets in certain regions of the country. Among other services, they facilitate competition by ensuring that even non-utility companies (such as demand response providers) have equal access to deliver into the grid.

Figure 123: US electric smart meter deployments, 2008-13 (m units)

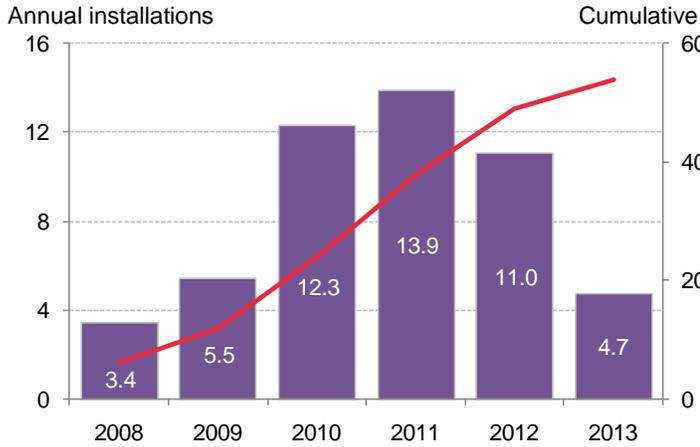
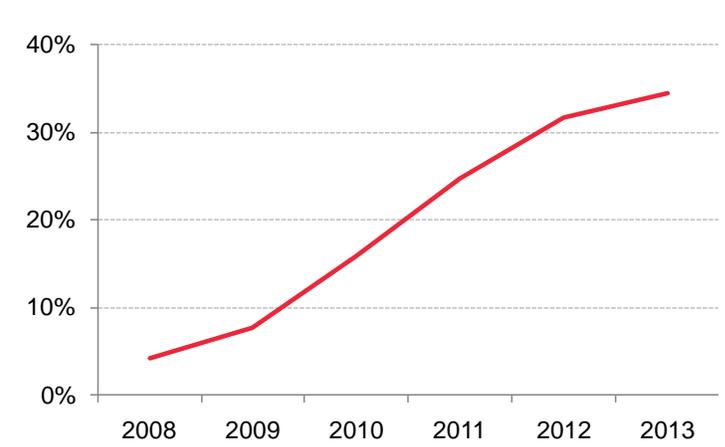


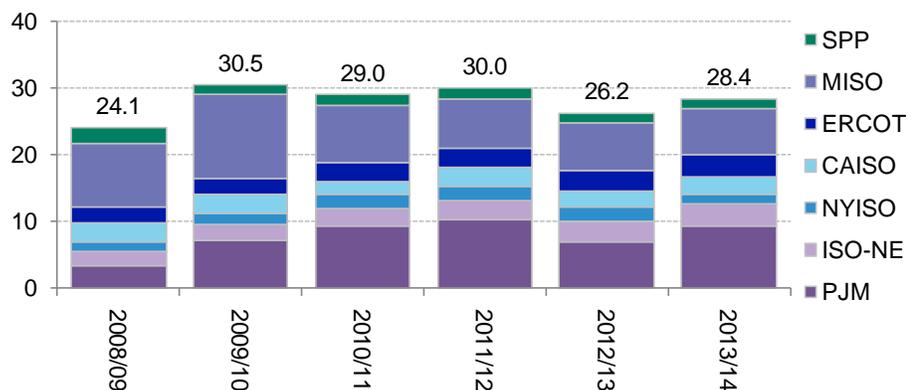
Figure 124: US electric smart meter penetration (smart meter deployment as percent of total US electricity customers)



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

As for demand response, capacity growth has been strong over the last six years, driven in particular by programs in the ISO / RTO markets. 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 30GW in 2011 before dropping down to 26GW in 2012 primarily due to rule changes in PJM, the largest global demand response market (Figure 125). PJM, ISO-New England and the New York ISO are viewed as three of the most proactive markets for promoting demand response because their respective capacity market programs have been particularly successful in stimulating demand-side participation.

Figure 125: Incentive-based demand response capacity by US ISO/RTO, 2008/09-2013/14 (GW)



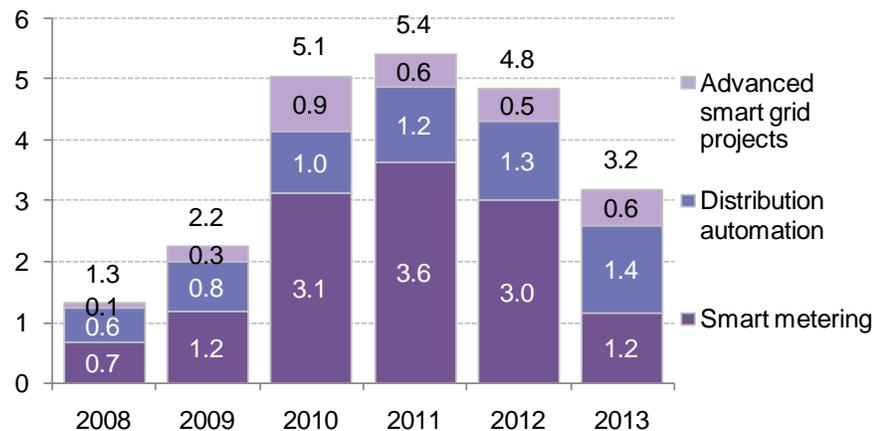
Source: Bloomberg New Energy Finance, data from ISOs Note: These figures include demand response activity driven by customer curtailment, as well as by behind-the-meter generation, since the ISOs do not provide this break-out. This figure does not include residential demand response programs that are not bid into capacity markets. Years are shown in two-year increments to reflect how the largest market, PJM, operates: demand response capacity is cleared in forward capacity auctions for delivery years which typically run from June to May.

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, including programs outside of the ISO/RTO markets) is at 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 2010 and \$5.4bn in 2011 as stimulus-funded projects got underway (Figure 126).

Figure 126: US smart grid spending by segment, 2008-13 (\$bn)



Source: Bloomberg New Energy Finance Note: The 'Advanced smart grid projects' 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. This trend continued in 2013, when total smart grid spending dropped to \$3.2bn. Smart metering spending decreased the most from 2011 to 2013 and is now just over a third of what it was when stimulus-funded projects were in full swing. Spending on distribution automation and advanced smart grid projects were relatively stable from 2011 to 2013.

Economics

The business case for smart grid investment differs widely between utilities, and typically consists of an array of benefits. 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 in cases of outage or other grid disruptions.

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 and solar to come onto to the grid.

Automated demand response can be quickly dispatched when such renewable resources are not available or supply becomes unpredictable.

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. Also, broader system reliability and flexibility benefits are not always well captured in the business case for smart grid projects.

For demand response, over 95% of revenues are 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. Capacity payments for demand response are only available in the northeast US forward capacity auctions. Other states have specific demand response programs that provide fixed capacity payments for capacity under fixed contracts, often administered by third-party providers. Revenues from ancillary services comprise another portion of the revenues. Together, capacity and ancillary service revenues range from several thousand dollars to tens of thousands of dollars per megawatt of capacity per year, depending on factors such as market location, demand response contract terms, speed and accuracy of response to grid operator signals 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 is the leading player in the market for smart grid communication infrastructure and went public in March 2013. 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 (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. Most smart grid communication networks deployed in the US utilize wireless mesh technology but other technologies such as wireless point-to-point and cellular communication are also used.

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, asset management and volt-VAR optimization. Home area network deployments include in-home displays, smart thermostats, smart appliances and other load control devices. One indication that the market for home energy management is enticingly large and maturing was Google's January 2014 acquisition of Nest, a vendor known for its smart thermostats, for \$3.2bn.

Smart grid data management and analytics software have already attracted the attention of industry giants such as Oracle, SAP and IBM as well as a growing crowd of start-up companies. While this area remains nascent, it offers utilities the ability to capitalize on several 'second order' smart grid benefits such as improved customer segmentation, better theft detection and improved program targeting.

A final but important development for the smart grid industry has to do with its role to enhance infrastructure resilience; investments in smart grid have been a focus of policy discussions in the aftermath of Hurricane Sandy. Smart grid technologies can help a utility more quickly and accurately identify areas with outages or other service issues during and after storms, facilitating the recovery process and allowing utilities to prioritize critical areas. Smart grid technologies combined with infrastructure hardening (stronger power lines and poles, raised and waterproof substations, etc.) can improve the reliability and resiliency of power networks greater than either approach alone.

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 products and services operating in the US include EnerNOC, Comverge, Constellation Energy, Energy Curtailment Specialists (bought by NRG), Johnson Controls, Honeywell, GE, Siemens, Schneider-Electric, Ingersoll-Rand/Trane, Enbala Power Networks and Viridity Energy.²⁴

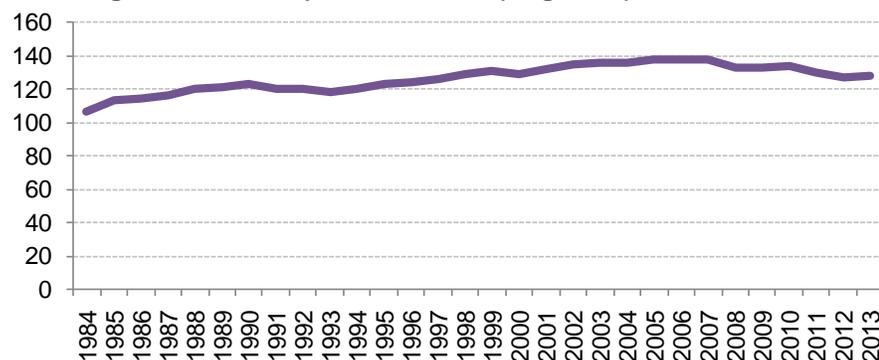
²⁴ Some of these players do not actually bid in demand response, but rather work with others to help implement - reductions, or enable their building customers to participate in demand response programs.

SECTION 7. SUSTAINABLE TRANSPORTATION

The US ground transport sector is undergoing a major transition prompted by innovative technologies, the implementation of new policies, and the availability of low-priced domestic natural gas. Corporate average fuel economy (CAFE) standards call for doubling of fuel economy for US light-duty vehicles by 2025, relative to 2011 averages. Strict fuel economy and emission targets set in 2012 are already paying off. Hybrids, plug-in electrics, and natural gas vehicles (NGVs) are growing in prominence; sales for the first two reached almost 600,000 vehicles in 2013 (3.8% of US passenger vehicle sales), and natural gas demand from the transport sector is up 33% since 2007. In addition, a number of major automakers remains committed to commercial roll-out of fuel cell electric vehicles (FCEVs) by 2015.

Innovative vehicle technologies and fuel efficiency improvements in conventional vehicles, in addition to changes in consumer behavior such as lower vehicle miles travelled, are contributing to the drop in gasoline consumption from its 2005 peak.

Figure 127: US gasoline consumption, 1984-2013 (bn gallons)



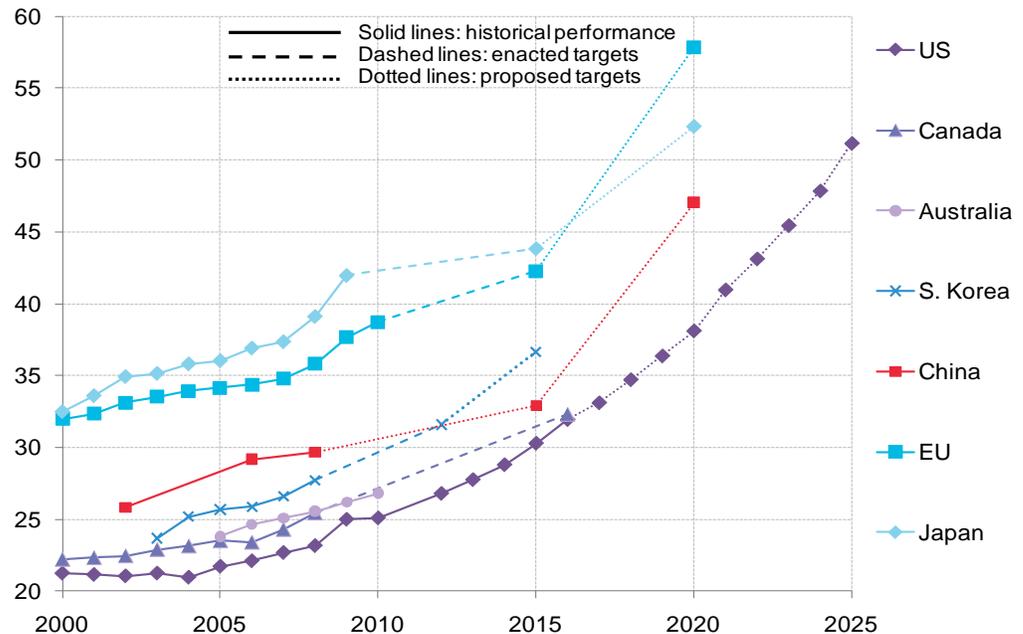
Source: Bloomberg New Energy Finance, EIA Note: Analysis is based on daily averages of "total gasoline all sales / deliveries by prime supplier".

7.1. Electric vehicles

Policy

Various policy mechanisms have boosted demand for hybrids and electric vehicles. 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 brings the US CAFE standard closer to that of Europe and Japan by 2025 (Figure 128). These strict fuel economy and emission targets are already paying dividends, with light-duty vehicles reaching historic performance levels. Model year (MY) 2012 CAFE reached an all-time high of 23.6 miles per gallon (mpg), 5.4% higher than MY2011.

Figure 128: 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 (CARB) Zero Emission Vehicle (ZEV) program has been inducing auto manufacturers to produce a certain quota of alternative vehicles (eg, fuel cell, hybrid, plug-in hybrid, and battery electric vehicles) for sale in the state since 1990. Though the ZEV program has been controversial, it has had a lasting impact on the availability of alternative vehicles. CARB's stricter set of regulations, which are coming into effect in 2018, are expected to lead to 1.5m ZEVs in California by 2025.

In addition, 10 states – Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, New Mexico, Oregon, Rhode Island, and Vermont – along with Washington DC follow the current CARB regulations. While under existing regulations, manufacturers can claim ZEV credits for hybrid vehicles, starting in 2018, only fuel cell, plug-in hybrid and battery electric vehicles will receive credits. In October 2013, seven of those 10 states signed an agreement with California setting the stage for adoption of the stricter ZEV rules, with the goal of achieving 3.3m ZEVs on the roads of the eight states by 2025.

Separately in October, all three Pacific states (California, Oregon and Washington), along with Canada's province of British Columbia, signed a broad agreement on measures to combat climate change including a commitment to take steps to expand the use of ZEVs, aiming for 10% of new public and private fleet vehicle purchases by 2016.

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 \$8.4bn to Ford Motor, Nissan North America, Tesla Motors, Fisker Automotive

and Vehicle Production Group, under the Advanced Technology Vehicles Manufacturing (ATVM) loan program. While the bankruptcies of Vehicle Production Group and Fisker Automotive have resulted in criticism of the ATVM loan program, the loans to those two bankrupt entities amounted to only 2.6% of the \$8.4bn lent. In 2013, Tesla paid back its \$465m loan, nine years ahead of time. Ford and Nissan continue to make timely payments on their loans.

Aside from the ATVM loan program, the American Recovery and Reinvestment Act of 2009 also supported projects to deploy electric drive infrastructure and provided grants totaling \$2.4bn through the Electric Drive Battery and Component Manufacturing Initiative. Additionally there have grant programs supporting R&D on critical technologies such as batteries.

To accelerate demand for electric vehicles, the federal government has also provided tax credits, starting at \$2,500 for the purchase of a plug-in electric vehicle with a 4kWh battery, and increasing by \$417 per kWh of battery capacity 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.

The federal tax code also provided, through 31 December 2013, a credit for alternative fuel vehicle refueling property, which includes electric charging infrastructure. The credit covers 30% of cost, up to \$1,000 for residential and \$30,000 for commercial property.

There are also complementary state-level incentives to purchase electric and hybrid vehicles and associated charging infrastructure.

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

- Light-duty fuel cell electric vehicles (not more than 8,500lb, usually passenger vehicles) placed in service after 31 December 2009 may receive a base 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, the credit for a vehicle increases by \$1,000-4,000 per vehicle depending on the amount by which it exceeds 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 DOE 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 range of \$2-4/gallon of gasoline equivalent (in 2007 dollars) by 2020. This price range represents the cost at which hydrogen fuel cell electric vehicles (FCEVs) are projected to become competitive on a cost per mile basis with gasoline-fueled vehicles. 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.

To further support deployment of hydrogen refueling infrastructure, in 2013 the DOE launched a public-private partnership, H₂USA. Current members include auto manufacturers (eg, Chrysler, Daimler, GM, Honda, Hyundai, Nissan and Toyota), state-level associations (eg, California Fuel Cell Partnership, Massachusetts Hydrogen Coalition), industrial associations (eg, the American Gas

Association, Association of Global Automakers, the Electric Drive Transportation Association, the Fuel Cell and Hydrogen Energy Association) and hydrogen value-chain players (eg, Linde, ITM Power, Proton OnSite). In total there are currently 26 participants. The goal for H₂USA is to contribute to:

- Establishing necessary hydrogen infrastructure and leveraging multiple energy sources, including natural gas and renewables
- Deploying FCEVs across America
- Improving America’s energy and economic security
- Significantly reducing GHG emissions
- Developing domestic sources of clean energy and creating jobs in the US
- Validating new technologies and creating a strong domestic supply base in the clean energy sector.

Aside from the federal initiatives, there continues to be state-level efforts via California Fuel Cell Partnership and the Hawaii Hydrogen Initiative (H2I) that are supporting the roll-out of hydrogen refueling infrastructure in preparation for commercial launch of fuel cell vehicles in 2015.

Deployment

At the end of 2013, the US passenger vehicle market included 49 hybrid models (five more than 2012), 10 battery electric vehicle (BEV) models (two more than 2012) and six plug-in hybrid electric vehicle (PHEV) models (two more than 2012) available for sale to the general public. The contribution of BEVs and PHEVs was modest at the beginning of 2013; yet by year-end, total annual sales figures over the 12 months for these two types had climbed to 96,952 vehicles – almost twice that of total EV sales in 2012. Among the PHEVs and BEVs, leading models were Chevrolet Volt at 23,094 units, Nissan Leaf at 22,610 units and Tesla Model S at 19,000 units. Hybrid vehicle sales also increased by 14% compared with 2012 to 495,685 units. Combined, hybrids, BEVs, and PHEVs achieved 592,637 sales in 2013.

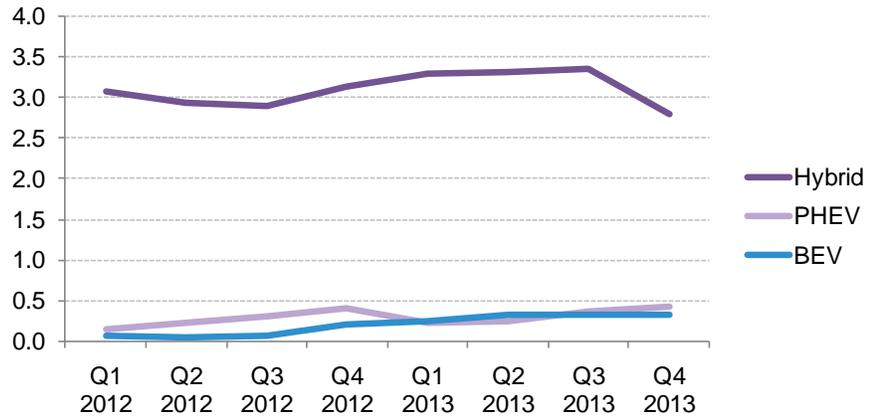
Figure 129: US passenger hybrid, plug-in hybrid and battery electric vehicle sales, 2012-13 (thousand units)



Source: Bloomberg New Energy Finance

As a percentage of total US 2013 passenger vehicle sales, hybrids are 3.19% (up by 6% on 2012), PHEVs are 0.31% (up by 19% on 2012), and BEVs are 0.31% (up by 233% on 2012) (Figure 130). Together, these three types accounted for 3.8% of US passenger vehicle sales.

Figure 130: Hybrid, plug-in hybrid and battery electric vehicles as percentage of total US passenger vehicle sales, 2012-13 (%)



Source: Bloomberg New Energy Finance

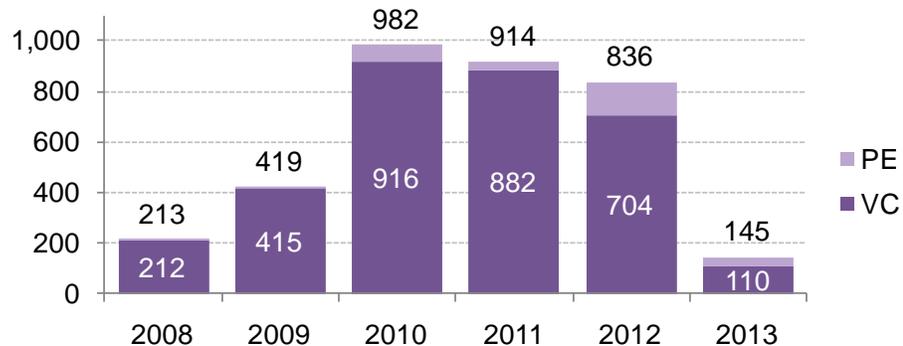
While US BEV and PHEV sales may seem modest compared with the size of the US fleet, the uptake of electric vehicles has also been far faster than the initial introduction of hybrid vehicles in US. Additionally, the country has cemented its position as the world’s largest EV market and has the widest selection of mass-produced BEVs and PHEVs.

Another innovative transport technology is fuel cell-powered vehicles. Deployment of these is minimal to date, but auto manufacturers are developing plans for commercialization (more on this in ‘Market dynamics’ below).

Financing

Over the last six years, venture capital and private equity (VC/PE) firms have invested over \$3.5bn of private capital in the US clean transportation sector (Figure 131).

Figure 131: 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.

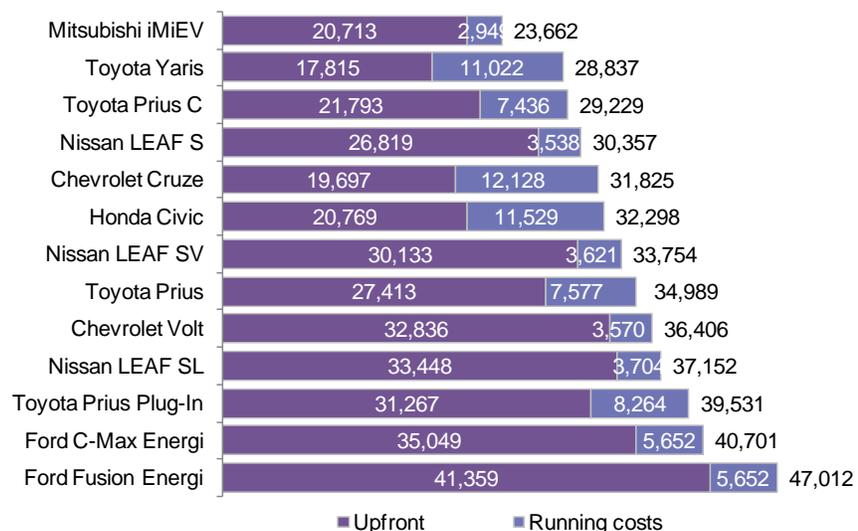
Not all these investments have been fruitful as exemplified by the bankruptcies of PHEV manufacturer Fisker Automotive, and battery-swapping pioneer Better Place which had raised over \$2bn from investors. These bankruptcies are among the factors that can explain the sharp drop in VC/PE investment in the US advanced transportation sector. However, Tesla, which went public in 2010, has been a notable success. In May 2013, the company raised over \$1bn by issuing additional shares, enabling the company to pay back its DOE ATVM loan nine years ahead of schedule while establishing cash reserves as it ramps up production of its Model S and prepares for the launch of its

Model X toward the end of 2014/early 2015. At its peak in 2013, Tesla’s stock price reached \$193, or 5.5x that of its opening price on the first day of trading in 2013. While its gains were pared back by the end of the year, it still finished 2013 at \$150.

Economics

In 2013 auto manufacturers starting with Nissan lowered prices on their electric vehicle offerings. The result has been that for some models, such as the Mitsubishi iMiEV, the upfront price after federal subsidies is already lower than most vehicles on the market. Depending on the driving characteristics of the owners, the total costs of ownership of several electric vehicles are now competitive with gasoline-fueled vehicles in the same class (Figure 132). In addition, with more electric vehicle models expected to enter the market in the coming years, there will be greater variety in vehicle classes and price points – introducing more possibilities for competitive products on the basis of total cost of ownership.

Figure 132: Total cost of ownership of select vehicles in the US (\$)



Source: Bloomberg New Energy Finance. Note: Upfront cost is after federal subsidies only, and includes taxes, registration and delivery charges, as well as EV charging equipment where necessary.

Table 5: 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 electric vehicle 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 behavior. Leasing is playing a significant role in the US electric vehicle market; while the average leasing rate across all passenger vehicles is 26%, the average rate across all electric vehicles is currently 39%, with some models offered as lease-only.

Table 6 shows a selection of established auto companies' electric vehicle plans, partnerships, and supply chain relationships.

Table 6: Electric vehicle plans, partnerships, and supply chain relationships for major auto companies

Company	Plans	Battery and EV component production
Daimler	<ul style="list-style-type: none"> • Third edition Smart EV in 2012 • Small quantity production of Mercedes SLS e-drive from 2013 	<ul style="list-style-type: none"> • Investment in Tesla • Joint venture with Evonik: li-Tec • Joint venture with Bosch for EV motor production: EM-motive
BMW	<ul style="list-style-type: none"> • Launched the i3 BEV in 2013 in Europe, already has 10,000 orders • Launching the i8 PHEV in 2014 	<ul style="list-style-type: none"> • Batteries supplied by Samsung SDI through Bosch • Joint venture with PSA Peugeot Citroen for EV powertrain components • Fuel cell partnership with Toyota may cover electric drive components for EVs
Volkswagen	<ul style="list-style-type: none"> • Four Audi models • Up E-motion in 2013 and E-Golf in 2014 	<ul style="list-style-type: none"> • Batteries supplied by Panasonic
Nissan - Renault	<ul style="list-style-type: none"> • Nissan Leaf on sale globally is the bestselling EV nearing the 100k mark since launch in 2011. • Nissan e-NV200 commercial van to go on sale globally in 2014 • Renault has four EV models on sales in Europe: Fluence, Kangoo, Twizy and Zoe 	<ul style="list-style-type: none"> • Batteries for Nissan supplied by joint venture with NEC – AESC • Batteries for Renault supplied by LG Chem
PSA Peugeot Citroen	<ul style="list-style-type: none"> • Sells rebadged Mitsubishi i-MiEVs 	<ul style="list-style-type: none"> • Joint venture with BMW for EV powertrain components
Toyota	<ul style="list-style-type: none"> • Prius Plug-in on sale globally since 2012 • Limited production (2,600) of RAV4 EV and iQ Scion (1,100) 	<ul style="list-style-type: none"> • Batteries supplied by Panasonic for Prius • Tesla supplies battery packs for RAV4 EV, with cells originally from Panasonic
Hyundai / Kia	<ul style="list-style-type: none"> • Limited production of the BlueOn and Kia Ray from 2012 as a trial 	<ul style="list-style-type: none"> • Battery supply from LG Chem and SK Innovation
GM	<ul style="list-style-type: none"> • Chevrolet Volt on sale in North America and Europe since 2011 • Chevrolet Spark BEV on sale in US from 2013 • Cadillac ELR PHEV on sale in 2014 	<ul style="list-style-type: none"> • Batteries from LG Chem for the Volt and Cadillac ELR, A123 for the Spark EV and Hitachi Vehicle Energy for Buick micro-hybrids • New plant for EV motor production online in 2012
Ford	<ul style="list-style-type: none"> • Ford Focus Electric rolled out in 2012 • Launched Fusion Energi PHEV in 2012 and C-Max Energi PHEV in 2013 	<ul style="list-style-type: none"> • Battery supply from LG Chem for Focus Electric • Battery supply from Panasonic for hybrids and PHEVs
Mitsubishi	<ul style="list-style-type: none"> • Continued production of i-MiEV and i-MiEV Minicab • The Outlander PHEV on sale in Japan and Europe in 2013, US launch in 2014 	<ul style="list-style-type: none"> • Battery joint venture with GS Yuasa – Lithium Energy Japan • Secondary supply from Toshiba
Honda	<ul style="list-style-type: none"> • Fit/Jazz EV launch in 2012 • Accord Plug-in launch in late 2012 	<ul style="list-style-type: none"> • 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

Passenger fuel-cell powered vehicles are currently not available for direct sale to customers. Lease offers, though, are available. Starting in 2008, though, Honda leased out its fuel cell vehicle, the FCX Clarity, in southern California under a three-year \$600/month program that concluded in 2012. Hyundai is planning to lease out the Tucson fuel cell vehicles starting in 2014 (Table 7).

Table 7: Fuel cell vehicle plans of major auto companies

Manufacturer	Fuel cell vehicle fleet status	Indication of planned activity / notes on strategic partnerships
Daimler	240 FCVs on the road in US, Germany, Japan, Singapore	500-1,000 FCVs by 2015 Daimler has a fuel cell partnership with Nissan and Ford.
Ford Motor Company	30 over 2004-09 in the US, Canada and Europe	Unlikely to commercialize by 2015 ⁽¹⁾ Ford has a fuel cell partnership with Daimler and Nissan.
General Motors Corporation / Opel	115 Chevrolet Equinox FCVs in US	Next generation fuel cell vehicle to be commercialized in 2015 In 2013, it signed a long-term partnership with Honda for co-development of fuel-cell powertrains and hydrogen storage technologies by 2020.

Honda Motor Co	~200 FCX Clarity cars leased in California, Japan & Europe	Committed to commercialization in 2015 In 2013, it signed a long-term partnership with GM for co-development of fuel-cell powertrains and hydrogen storage technologies by 2020.
Hyundai Kia Automotive Group	80 vehicles in Korea (50 Seoul, 30 Ulsan)	Planning to lease out the Tucson fuel cell vehicle starting in 2014 with a \$2,999 down payment and a monthly payment of \$499 for a 36-month period. The lease package includes the cost of fuel.
Renault SA & Nissan Motor Co (alliance)	~20 X-Trail FCVs	Nissan aiming to launch FCVs by 2017 Earlier in 2013, Nissan joined the fuel cell partnership between Daimler and Ford.
Toyota	Global testing of a fuel cell powered SUV, the Toyota FCHV-adv	Committed to commercialization 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."

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 (NGV) 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 fueling 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). These incentives expired at the end of 2013 but could be extended again by Congress. 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 GHG emissions, and minimum procurement of 'alternative fuel vehicles'. NGVs can contribute to meeting these standards.

State and local governments have adopted further incentives. These include vouchers and rebates for the purchase of NGVs, state-funded grants for fueling 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 US transport sector grew at a rapid compound annual growth rate of 7% over 2001-13 and jumped by 9% in 2013 relative to 2012 (Figure 133), though it still accounts for just a sliver of overall natural gas demand. The market can be divided into two groupings based on the type of fuel used: CNG or LNG. While a natural gas engine can run on either CNG or LNG – the on-board storage tanks and fueling lines differ – LNG has a higher energy density and is often preferred for longer routes and/or higher horsepower. (The make-up of these two groupings is described below, and the rationale for why certain vehicles would prefer CNG and others LNG is provided in the 'Economics' section.)

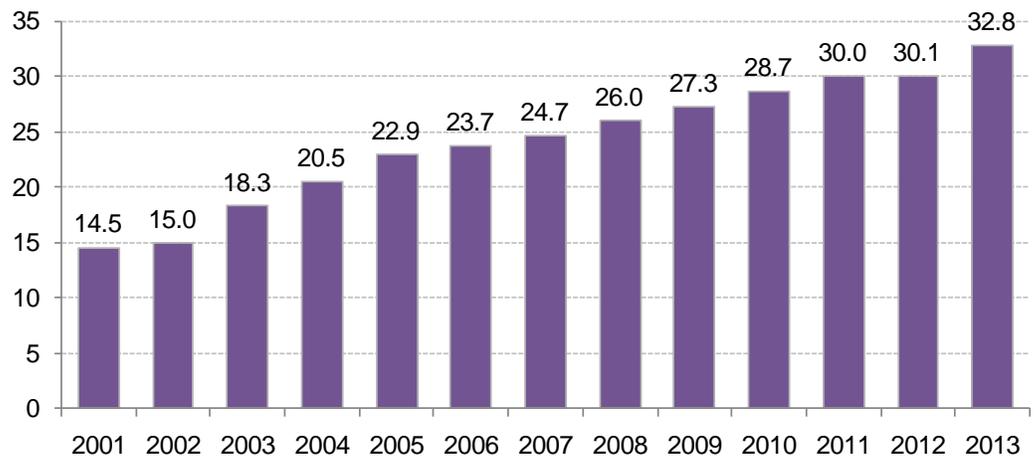
CNG vehicles have gained a foothold in the municipal fleet market, especially in transit bus fleets, and have made substantial progress in the refuse truck segment. About one-fifth of all transit buses were fueled by CNG or LNG in 2012, and almost half of the refuse trucks purchased in 2013 were powered by natural gas. Refuse trucks consume just under 10,000 gallons of gasoline equivalent (GGE) per year, compared with just 531 GGEs for light-duty vehicles. This disparity in fuel use provides

substantial fuel cost savings for fleets with high fuel use, due to lower CNG costs compared with diesel or gasoline. Often, high fuel-use fleet vehicles also centrally refuel at the location where they reside, thus minimizing the need for additional public fueling structure. These centrally fueled, high fuel-use fleets represent the fastest-growing CNG market.

LNG's target market in the US – heavy-duty transport – is much larger than that of CNG. LNG use for heavy-duty vehicles is growing, but is still in its very early stages and penetration is currently very low. LNG consumption from the heavy-duty sector would be 10Bcfd if all heavy-duty trucks switched to LNG. Other sectors, such as oilfield services, have much higher 'per unit' LNG demand (ie, one hydraulic fracturing job uses substantially more fuel than one truck trip), but a smaller overall market. LNG fuel sellers often offer complete services to customers, from providing the fuel to building storage and fueling infrastructure, to help build demand. Some fuel suppliers are planning production plants without fully contracting capacity, taking on merchant risk.

As of 2011 (the most recent year for which EIA data is available), there were approximately 118,000 CNG- and 3,400 LNG-fueled vehicles on US roads, up from 101,000 and 2,000 in 2000, respectively.²⁵

Figure 133: US natural gas demand from natural gas vehicles, 2005-13 (Bcf)



Source: EIA, Bloomberg New Energy Finance Note: Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2013). Data excludes gas consumed in the operation of pipelines.

Financing

One measure of financing activity is investment in infrastructure deployment. Indeed, lack of infrastructure is one of the biggest barriers to substantial further development of NGVs. There are currently around 1,300 CNG and only 84 LNG fueling stations in the US, compared with around 119,000 gasoline/diesel stations. 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 fueling infrastructure that will open up key corridors.

One company – Clean Energy Fuels – planned 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 company now estimates it will reach that goal sometime in 2014. The intended schedule

²⁵ According to the most recent data from the EIA.

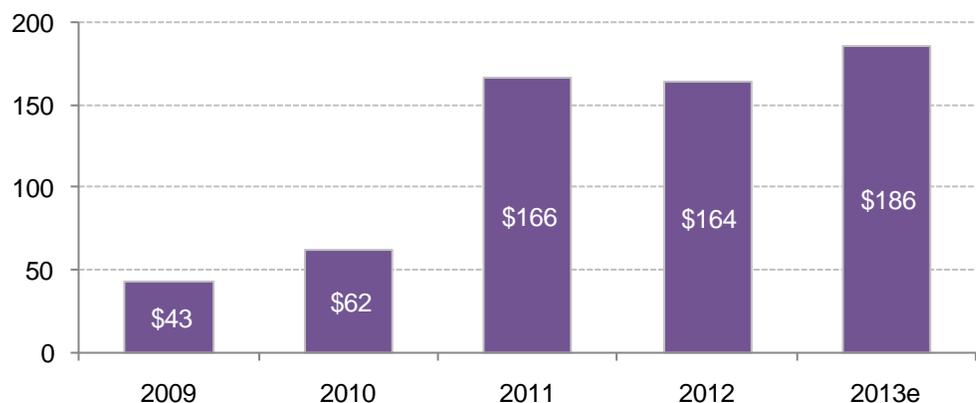
Table 8: Natural gas fueling stations

	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
2013*	1,290	84

Source: Bloomberg New Energy Finance, DOE Note: As of 25 December 2013

was delayed waiting for demand: the commercial roll-out of Cummins Westport's²⁶ 12-liter natural gas engine, one of only several natural gas engines available for long-haul trucks, went into production in mid-2013 compared to its expected availability earlier in the year. The engine is used in truck models from Daimler, PACCAR and Volvo.

Clean Energy's business model is to build sufficient fueling infrastructure within high-use corridors to allow trucking companies to take a regional approach to conversion. (85% of US trucking is regional in nature, with fairly fixed routes.) Figure 134 shows the level of asset financing activity, most of which is poured into building fueling infrastructure, undertaken by Clean Energy. (These investment figures serve as an indicator of financing in the natural gas vehicle industry, but by no means account for the entire amount of investment activity.)

Figure 134: Capex investments by Clean Energy Fuels, mostly for new natural gas fueling stations, \$m 2009-13e

Source: Clean Energy Fuels Corp, annual report 2012 Notes: Figures from 2009-12 reflect 'net cash used in investing activities' as per company's cash flow statement. The amount for 2013 is based on company plans ("Our business plan calls for approximately \$186.2 million in capital expenditures in 2013"); note that its expected 2013 capex was revised down by about \$53m between its 2011 and 2012 reporting, reflecting the company's adjusted plans for fueling station build in 2013.

Economics

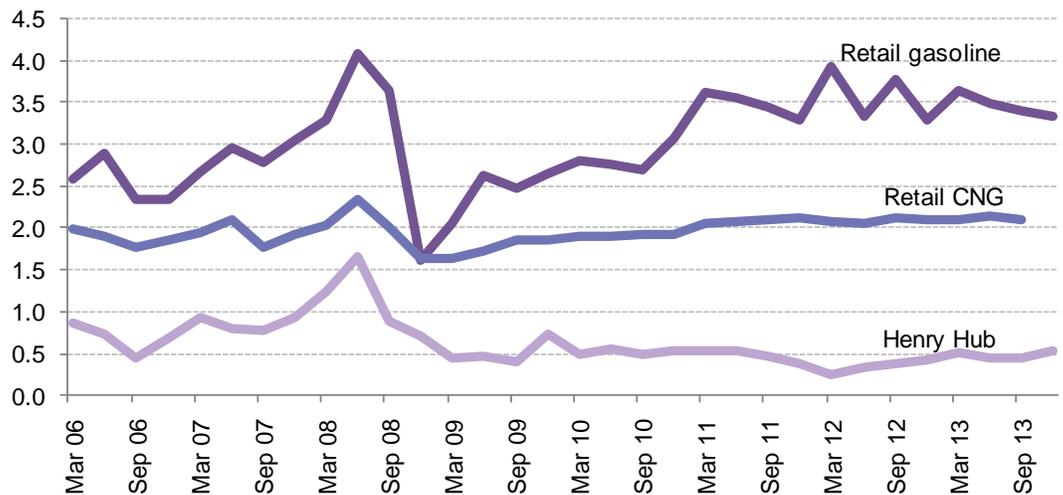
While natural gas engines function almost identically to gasoline/diesel engines, new fueling systems are needed. Therefore, a fuel-price discount is needed to incentivize consumers to convert (Figure 135).

The economics naturally favor 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, NGVs 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, the two fuels are best fit for different market segments. The latter's higher energy density but more complicated fueling 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 (eg, refuse trucks, buses).

²⁶ A joint venture between Cummins and Westport Innovations that focuses on natural gas engines for commercial transportation (eg, heavy-duty transport trucks and buses).

Figure 135: CNG prices compared with gasoline and Henry Hub natural gas prices, 2006-13 (\$/GGE)



Source: Bloomberg New Energy Finance, US DOE Alternative Fuels Data Center

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.

Market dynamics

There is considerable evidence showing CNG gaining traction in its key segments. Waste Management and Republic Services, the two largest waste disposal companies in the US, are systematically converting their fleets to CNG, and cities such as Los Angeles and Phoenix have most of their transit buses fueled with natural gas. One advantage for CNG is that station builders and consumers are often the same entity (eg, Waste Management owns and operates both CNG refuse trucks and fueling stations). Even if they are not, station owners can anticipate volumes with a great deal of confidence. Similarly, some LNG stations are built privately for fleets, or station developers partner with a customer to guarantee demand (for example, in November 2013 UPS, the largest parcel delivery company in the US, partnered with Clean Energy Fuels to develop public LNG stations accessible by its fleets in Texas).

As noted above, the primary obstacle for the industry concerns insufficient infrastructure – a problem being tackled by Clean Energy and other groups such as Shell and BluLNG (a venture between China's ENN Group and Utah-based CH4 Energy).

On the vehicle side, Table 9 below shows a list of light-duty CNG vehicles available in 2014, divided into 'bi-fuel' (ie, the vehicle runs on CNG but can switch to gasoline or diesel when CNG fuel runs out) and 'dedicated' (the vehicle runs only on CNG).

Table 9: List of light-duty CNG vehicles available in 2014

Bi-fuel CNG vehicles	Dedicated CNG vehicles
Chevrolet - Silverado 2500 HD	Chevrolet - Express 2500/3500, 2WD
Ford - E-350/450 Cutaway	GMC - Savana 2500/3500, 2WD
Ford - E-350/450 Cutaway	GMC - Savana 3500/4500 Cutaway
Ford - E150/250/350	Honda - Civic

Bi-fuel CNG vehicles	Dedicated CNG vehicles
Ford - F-150	
Ford - Super Duty, F-250/350/450	
Ford - Super Duty, F-350/450/550	
Ford - Super Duty, F-650/750	
Ford - Transit 150/250/350	
Ford - Transit 250/350	
Ford - Transit Connect	
GMC - Sierra 2500 HD	
Ram - 2500	

Source: US DOE Alternative Fuels Data Center

Table 10 shows the number of models currently available for different types of CNG heavy- and medium-duty vehicles platforms.

Table 10: Number of models available for CNG heavy- and medium-duty vehicle platforms

Over-the-road tractor	Refuse hauler	Transit bus	Shuttle bus	Vocational truck	Van	School bus	Street sweeper	Trolley
13	11	10	9	8	3	2	2	1

Source: US DOE Alternative Fuels Data Center

In terms of engine manufacturing, most engines top out at 9 liters which is often not large enough for heavy-duty long-haul transport trucks (though is sufficient for many medium-duty trucks). Westport Innovations offered a 15-liter engine that was discontinued in late 2013, but started producing a 12-liter, 400-horsepower engine (the ISX12-G) in August 2013. Other engine manufacturers MaxxForce (Navistar) and Volvo are on the verge of offering larger engines designed for regional and long-haul Class 8 over-the-road trucks within the next few years. These new engines will complement existing offerings, typically used in short-haul trucks, including the 8.9-liter Cummins Westport ISL G and the 7.6-liter MaxxForce ESI.

Though the future of the long-haul market currently rests on the performance of just one engine (the Westport ISX12-G), resulting in a tremendous amount of adoption risk, LNG supply is set to grow considerably over the next few years. Most existing supply comes from small-scale liquefaction plants owned by merchant fuel suppliers (ie, companies that build liquefaction plants mainly to supply the fuel) and gas utilities (which have legacy liquefaction capacity to meet peak gas demand).

There is also growing interest in renewable natural gas (RNG) as a substitute fuel for CNG and LNG in transportation, due to increased demand for ultra-low carbon fuels driven by the Renewable Fuel Standard (RFS2) and the Low Carbon Fuel Standard in California. RNG is derived from organic sources including, but not limited to, wastewater treatment facilities, landfills and anaerobic digesters. Resulting biogas needs to be upgraded to roughly 97% methane content in order to produce RNG, a product that is interchangeable with fossil-based natural gas. For example, Waste Management and Linde, an industrial gases company, commissioned a liquefaction plant at a landfill in California in 2009; the plant produces 13,000gpd LNG, enough to fuel Waste Management's fleet in the area.

According to the California Air Resources Board, RNG presents a nearly 90% lifecycle carbon reduction compared with gasoline and diesel. However, low-cost natural gas makes RNG production economically challenging, as the production costs for both CNG and LNG are lower than for RNG.

SECTION 8. CROSS-SECTORAL THEMES

This final section sweeps across the preceding analysis to extract recurring and important themes. These include federal climate policy; the country's emission track record; the growing interest in technologies and policies that ensure grid reliability and system resilience in the face of intermittency and disruptions; the transformative potential of distributed generation; innovations around financing; barriers to growth; comparisons of sustainable energy investment in regions within the US, and in this country relative to others; and the performance of the public markets as potential evidence of a sector on the rise.

8.1. Climate: a new federal policy focal point

Rarely during his first term did President Obama emphasize climate change as the primary motivation behind his administration's clean energy-friendly policies. Rather, the focus was often on economic development (job creation) and economic security. That changed in June 2013 with the release of the President's Climate Action Plan, intended to address the issue domestically and internationally – with or without the support of Congress.

Central to the plan is a directive to the EPA to establish emissions standards for new and existing power plants in the US. Standards for new power plants were proposed on 20 September 2013, while regulations on *existing* plants are due to be completed by 1 June 2014, finalized a year later, and effective in 2016.

Roughly translated, the regulations on new power plants effectively bar development of new coal-fired power, unless such plants come equipped with CCS technologies. Only relatively efficient natural gas plants can meet the ~1,110lbCO₂e/MWh emission standard detailed in the draft regulation, which is expected to be finalized in coming months. A typical coal-fired boiler emits twice that amount, absent CCS.

The Obama administration has promised a draft of standards for existing plants by June 2014. If the rule is as stringent as the one released for new plants, it would be a massive blow to coal-fired generation in the US. However, the White House has so far emphasized the EPA should “build on state leadership, provide flexibility, and take advantage of a wide range of energy sources...” in developing rules for existing plants. This has led many to believe the EPA will allow states to employ schemes targeting *fleet-average* emissions intensity reductions in lieu of the boiler-by-boiler mandates implemented by the EPA.²⁷ If permitted, some states may prefer to circumvent EPA regulations by implementing or joining state-wide cap-and-trade schemes like the Regional Greenhouse Gas Initiative (RGGI) or the Western Climate Initiative (WCI). This idea led to a flurry of climate rhetoric in late 2013.²⁸

27 “If states are not willing to develop implementation plans, the EPA will issue federal plans for them”, said EPA Administration Gina McCarthy in December 2013.

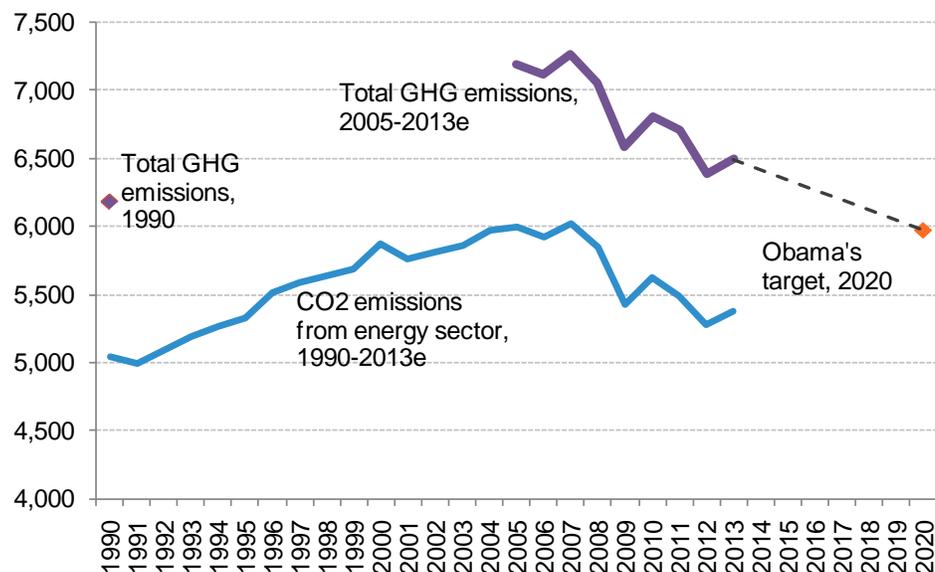
28 On 11 October, RGGI Chairman Collin O'Mara announced that five unidentified states were considering joining that cap-and-trade scheme. Four days later, Washington's governor said he wants a cap-and-trade program to curb economy-wide emissions in his own state. And on 24 October, California Governor Jerry Brown announced intentions to 'align' climate and clean energy policies with Oregon, Washington and British Columbia.

Whether it allows state-specific designs or simply promulgates a national mandate, the EPA is poised to play a decisive role in determining if the US hits its longer-term goal of cutting emissions 17% from 2005 levels by 2020. A report issued by the US State Department in September 2013 detailed the efforts the US is undertaking to address climate change and concluded that Obama's target is achievable, so long as the EPA's proposed regulations (or their equivalent) and other policies around efficiency, renewables, methane leakage and forest protection come to fruition.

8.2. CO₂ emissions: declining long-term despite a 2013 uptick

Total US GHG emissions have fallen by 9.8% since 2005, the baseline year cited by the White House. It is striking that, even without having established a legislated federal carbon reduction policy, the US is more than halfway to its goal of a 17% reduction (Figure 136). Whether that target can be achieved remains to be seen.

Figure 136: US GHG emissions, energy sector and economy-wide (MtCO₂e)



Source: Bloomberg New Energy Finance, US EPA, US EIA. Notes: 'Copenhagen target' assumes 17% reduction by 2020 on 2005 levels of total GHG emissions. The actual language of the announcement left vague whether the reductions applied to economy-wide emissions or just emissions of sectors that would have been covered under a federal cap-and-trade scheme. Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through September 2013). Data for total GHG emissions comes from EPA's Inventory of US Greenhouse Gas Emissions and Sinks (1990-2011), published April 2013. Data for CO₂ emissions from the energy sector comes from the EIA's Monthly Energy Review.

A large portion, 83%, of US GHG emissions are energy-related CO₂ emissions (the remainder come from other sectors and other gases). Both total GHG emissions and energy-related CO₂ emissions peaked in 2007 and have fallen by 10.6% (total GHG) and 10.8% (energy-related CO₂) since that peak.

Despite the longer-term trend downward, in 2013 CO₂ emissions actually ticked back up somewhat due to a short-term rebound in coal-fired generation. In the medium to long run, however, the fuel-switch trend is expected to continue as more coal capacity comes offline and is replaced by lower-carbon alternatives. CO₂ emissions from the energy sector will likely continue to drop.

Whether the US will reduce emissions sufficiently to hit the Obama administration's goal remains an open question to be determined by a combination of regulation (including the EPA rules on existing power plants plus others) and market forces.

8.3. Grid reliability and system resilience: more important than ever

The monumental changes depicted in this publication concern some electricity market operators and regulators for whom grid reliability is paramount. Wholesale retirement of coal plants removes gigawatts of reliable baseload capacity from the grid, while the growing role of renewables potentially raises the grid's vulnerability to intermittency. At sufficiently high levels of penetration, renewables create other challenges as well, including producing excess energy at some hours (such as during 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 there are other changes afoot in US energy, specifically intended to address these concerns. Smart grid infrastructure improves 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 and can be highly responsive to the grid's needs, ramping up rapidly to meet a surge in the load, or absorbing excess power (a capability known as decremental reserve). Natural gas plants have long been deployed as 'peakers' and can complement variable resources. Further new policies that take into account these changing conditions will likely be needed to ensure that markets fully recognize benefits associated with technologies that improve system flexibility.

Where electricity grid operators care about system reliability in the face of disruptions such as generation intermittency, end-users are increasingly focused on furthering resilience in the face of disruptions such as outages. Large energy consumers – such as residential buildings, industrial plants and data centers – are showing greater interest in energy procurement to make their facilities more energy secure and independent. As noted in Section 5.4, damage from natural disasters has risen, and nearly all of the costs of outages are borne by commercial and industrial customers, making self-generation and localized energy solutions increasingly attractive. Motivated by these and other reasons, corporations have become increasingly important customers for renewable energy and other applications featured in this report.

This attention to energy resilience, along with improved economics and favorable policy, explains the growing interest in specific forms of distributed generation (see below) and in microgrids – small versions of power systems that can combine various technologies, such as distributed solar, storage, CHP, diesel back-up, fuel cells, and smart grid systems – to meet a local electric load.

In the US, approximately 60% of microgrids are deployed at 'institutions' (eg, university campuses and government facilities), 30% at military bases, and the remainder at commercial and industrial sites and in residential neighborhoods. Federal support is limited, but microgrids can be backed by state incentives such as RPS (eg, by allowing RECs for PV or fuel cells on the system), specific funding (eg, Connecticut's microgrid funding), and reduction of standby charges in some states. Most vendors agree that market opportunities are largely in coastal, deregulated parts of the country: a combination of high retail prices, reduced utility market power, and the ability to gain revenues in wholesale/ancillary markets create a favorable market environment.

8.4. Distributed generation: transformative potential and a threat to business-as-usual

Both the promise and potential perils of distributed generation became more apparent 2013. In January, investor-owned utility industry trade association the Edison Electric Institute published an influential report about the challenges distributed generation poses for traditional players involved in the sale and delivery of electricity.²⁹ The report likens the disruptive potential of distributed generation to the impact that mobile phones had on the fixed-line telephony business and concludes that distributed generation, and other “transformative changes” will create “adverse impacts” on utilities’ revenues, returns, and credit quality.

What lies ahead for utilities when it comes to distributed generation is more important than the current situation. Most US electricity continues to be supplied by large-scale, centralized power plants. Distributed sources such as combined heat and power (CHP) and PV account for a small sliver of US generation. But the potential addressable market (\$360bn, by one estimate) is enormous, and investors are taking notice.

Utilities, regulators, and other stakeholders are beginning to digest the implications of this disruptive potential. As explained in Section 5.1, throughout 2013, intense political battles played out across the country over the appropriate treatment for distributed PV.

8.5. Cost of capital: critical to cutting sustainable energy costs

There has been considerable effort over the past decade to lower the equipment costs of sustainable energy technologies. While costs generally continue to decline, they are now doing so at a significantly slower rate, particularly in the case of wind and solar (in fact, prices for standard PV modules rose slightly in 2013). This is prompting the industry to seek cost reductions elsewhere and a particular emphasis has been on lowering the cost of capital.

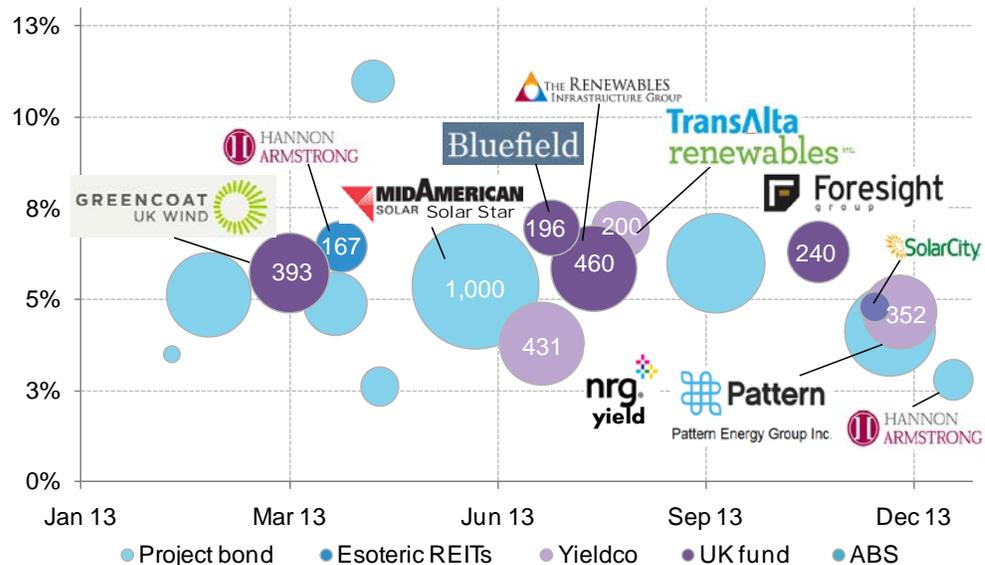
Investors and lenders tend to be comfortable with the risks associated with technologies such as wind and solar, and capital can typically be secured for projects with PPAs signed that seek to deploy equipment with a reliable performance record. Typically, such project financings are organized by a syndicate of financial institutions and private investors.

Still, project developers are aware that lower-cost sources of capital can be accessed via the public markets. In 2013, they made important strides in tapping these. The year saw a flood of activity in both project bonds and what can be described as ‘publicly traded clean energy investment vehicles’ (Figure 137). These are companies floated on a public exchange which own (mostly operating) assets. In North America, four types have either been used or vigorously pursued: master limited partnerships (MLPs), real estate investment trusts (REITs), Canada-based foreign asset income trusts (FAITs), and ‘yieldcos’. The latter two are currently available, while MLPs and REITs await sanctioning by the US government, either through legislation or regulation. The project bond market for clean energy projects topped \$3bn in 2013 and included a benchmark \$1bn issue backed by MidAmerican Energy’s newly acquired Solar Star PV project. In November 2013, SolarCity, the third-party financier, launched a first-of-a-kind solar securitization: a \$54m private offering of solar asset-backed securities. Securitization allows sustainable energy projects to access capital at a low cost, over a long tenor, and from a deep pool of investors. In December 2013, Hannon Armstrong closed a

²⁹ Edison Electric Institute, *Disruptive challenges: financial implications and strategic responses to a changing retail electric business*, January 2013

\$100m transaction for 'sustainable yield bonds', believed to be the first issuance of green bonds that quantifies its environmental impact, in terms of reduced GHG emissions.

Figure 137: Project bonds and publicly-traded clean energy investment vehicles in North America and the UK, 2013 (dividend yield %, transaction date, size)



Source: Bloomberg New Energy Finance, company filings. Notes: Y-axis shows dividend yield, x-axis shows date of IPO, size of bubble indicates transaction size (\$m). While these are classified as 'clean energy vehicles', some of them feature portfolios that include non-clean energy assets (eg, NRG Yield includes 2.9GW of fossil and thermal assets). Dividend yield is gross. Brookfield Renewable Energy Partners was formed in 2011 from a combination of earlier entities and thus did not have a dedicated IPO of its own – the value in this bubble represents funds raised by a secondary offering. 'REIT's are real estate investment trusts; 'ABS' is asset-backed securitization.

8.6. Barriers: remaining impediments to sustainable energy deployment

Growth in the deployment of many technologies highlighted in this report could be even more significant save for some significant barriers. Among the most notable of these:

- *Wavering or insufficient policy support:* the on-again/off-again nature of the PTC, for example, has created artificial booms and busts in the development of wind, geothermal, biomass, waste-to-energy, and hydropower projects. State regulators' unwillingness to implement time-based pricing has presented a barrier for other sectors.
- *High upfront costs for customers:* the business case in support of sustainable technologies often rests on a total net present value – whether the technology is better than the alternative over the lifetime of its use despite its seemingly high 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).

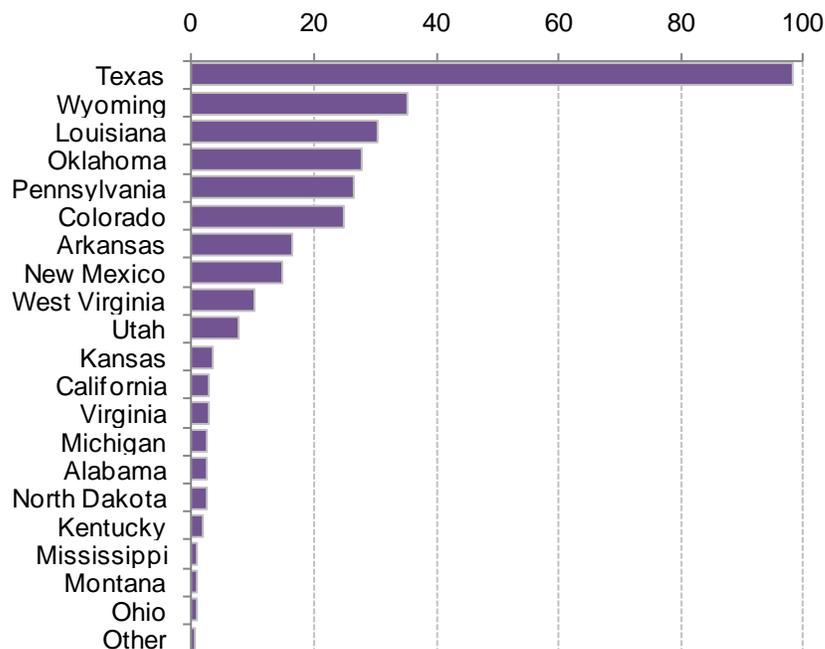
- *Insufficient enabling infrastructure:* some of the best wind resources in the US remain untapped due to insufficient transmission. Natural gas vehicle growth has been potentially restrained by the chicken-and-egg problem of insufficient fueling stations and operators' unwillingness to build them until more vehicles are on the road. 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 fueling stations.

8.7. Regional comparisons: leading and lagging states

Participation in the deployment of sustainable energy is hardly homogeneous across the country. Certain regions – such as Texas, Louisiana, and Oklahoma – sit on the richest reserves of shale gas (Figure 138). (Wyoming and Colorado also have abundant reserves but are somewhat distant from demand centers.) In the east, the Marcellus shale, much of it in Pennsylvania, has singlehandedly more than offset declines in dry gas production from elsewhere in the US.

Figure 138: US dry natural gas proved reserves by state, 2011 (Tcf)

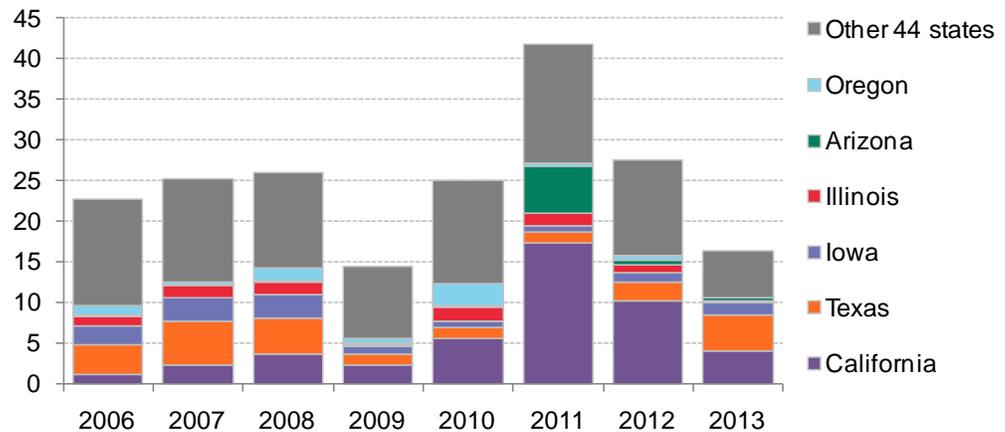


Source: EIA

In terms of renewable energy, looking at two asset classes (asset finance and venture capital / private equity), 54% of all investment in the US over 2006-13 occurred in six states. California accounted for 23% on its own. California's dominance in the clean energy sector is rooted in a combination of ingredients: a massive economy, progressive clean energy policies, high-quality resources (including solar, wind, and geothermal), high electricity prices, and penchant for venture capital.

The next three largest investors – Texas, Iowa and Illinois – are clean energy heavyweights for an entirely different reason: these three states lie squarely in the US ‘wind corridor’, where cheap land, low population density, strong wind resources and federal incentives make investment in wind turbines particularly attractive. But investment in some of these states has waned compared with the frenzy seen from 2006-08; this has to do with low gas prices, utilities having already easily complied with renewable procurement mandates, and local transmission constraints.

Figure 139: Investments in renewable energy by state, 2006-13 (\$bn)



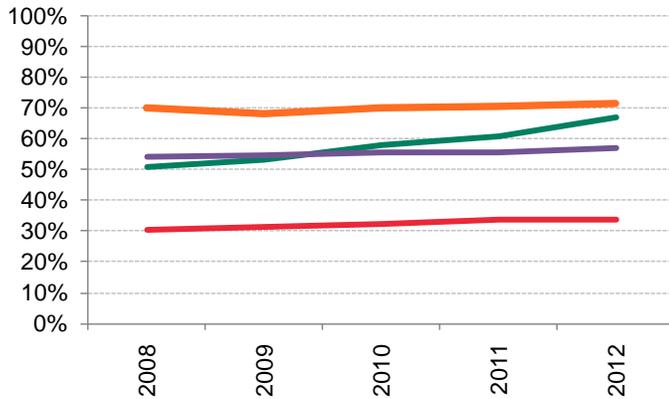
Source: Bloomberg New Energy Finance Note: This captures new build asset finance (ie, project investment) and VC/PE transactions for renewable energy deals. Asset finance excludes small distributed capacity. VC/PE excludes PE buy-outs as these are not new investment. In cases where a particular deal had more than one applicable state, the investment amount was allocated equally across each of the recipient states. For asset finance, the recipient state(s) are determined according to the location of the project(s) being financed. For VC/PE, the recipient state is determined according to the location of the organization raising the funds. The values shown here do not correspond to investment numbers shown in Figure 12 as this chart only includes two of the asset classes (AF and VC/PE), only includes renewable energy (and not other forms of clean energy), and only includes transactions with specified location.

Investment in renewable energy dominates the investment numbers shown in Figure 139, but other sectors also see this asymmetric mix of deployment across the country. Much of the state-to-state disparity has to do with policy. For example, demand response capacity is fragmented due to the variations in the rules that independent system operators have adopted for allowing the entry of these resources into the market, while fuel cell installations have tended to flock to states with attractive incentives, such as Connecticut, Delaware and California. A scorecard that measures energy efficiency policies across the 50 states shows that those in the Northeast and along the Pacific coast lead the way in terms of strength of policy positions.

8.8. Cross-country comparisons: the US in context

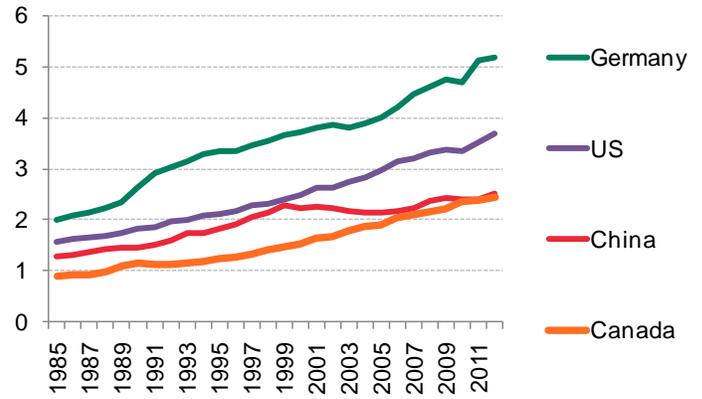
Figure 140 shows the role that natural gas and renewables are combining to play in US power generation compared with other countries. If renewable energy has climbed swiftly as a percentage of capacity and generation in the US, it has rocketed up at a blistering pace in Germany where it accounts for 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 natural gas as the US. Figure 141 shows the ratio of these countries' GDP to the amount of electricity generated by these countries. Much of the discrepancy across these countries has to do with relative size of sectors. All show increasing efficiency (decreasing energy intensity), though at different rates.

Figure 140: Contributions from natural gas and renewables as a share of national total nameplate capacity, 2008-12 (%)



Source: Bloomberg New Energy Finance

Figure 141: GDP per unit of electricity generated, 1985-2012 (GDP on purchasing power parity basis, in \$bn, per TWh)



Source: IMF World Economic Outlook, BP Statistical Review

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.

8.9. The energy independence dream: getting closer

On the back of the trends described herein, especially the trend associated with rising production of oil and gas, the balance of trade for US energy flows has reversed course over the last seven years. The country is becoming decreasingly dependent on energy imports, as the gap between domestic consumption and production narrows. Net energy imports are estimated to have fallen by 15% between 2012 and 2013 and by more than 50% since 2005 (Figure 142). The dynamic is striking when it comes to oil: the US imported 34% of the oil it consumed in 2013, compared with more than 60% in 2005, and October 2013 marked the first time since early 1995 that US crude oil production surpassed imports (Figure 143). In terms of natural gas, even as the US prepares for a future of LNG-based exports to Europe and Asia, pipeline exports to neighboring countries have already seen major growth: since 2003, US natural gas pipeline exports to Mexico have doubled, and to Canada have more than tripled.

Figure 142: US primary energy consumption, production, and net imports, 1981-2013 (quadrillion Btu)

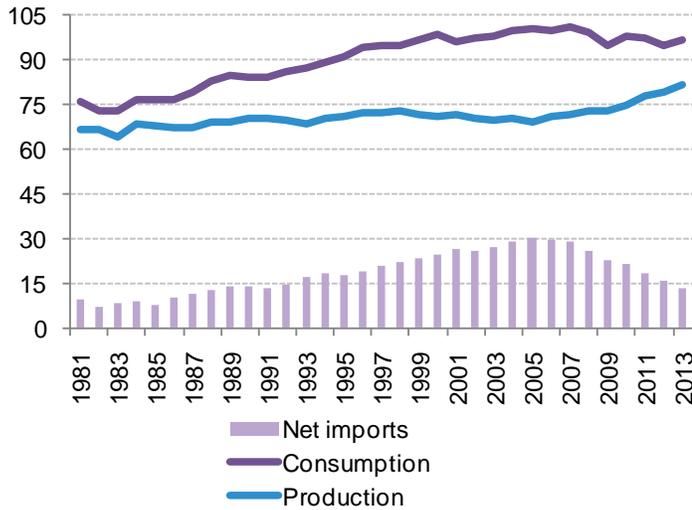
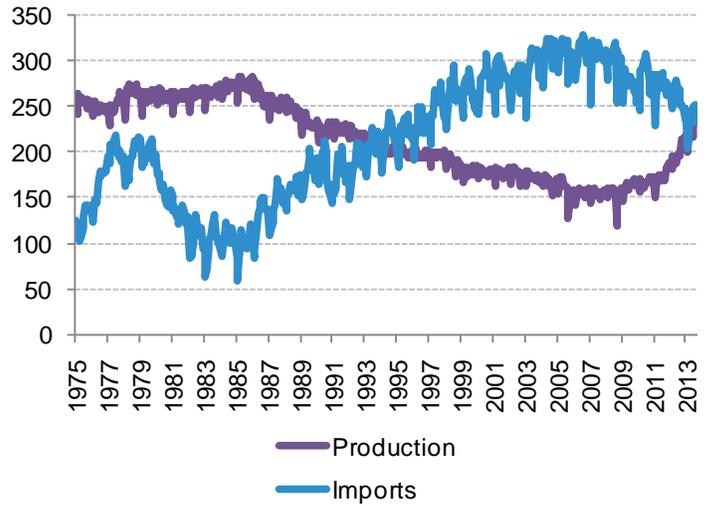


Figure 143: US crude oil production and imports, 1975-2013 (million barrels per month)



Source: EIA Notes: Values for 2013 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through September 2013 for primary energy consumption, production and net imports, and through October 2013 for crude oil production and imports).

This trend has substantial implications for economic competitiveness and for geopolitics – and, by extension, for policy-makers and market players. Policies (both abroad and at home), infrastructure, and strategies that were designed before this trend took shape may need to be re-examined and perhaps overhauled.

ABOUT US

Subscription details

sales.bnef@bloomberg.net

Authors of the report

Ethan Zindler	Head of Policy Analysis
Michel Di Capua	Head of Research, North America
Meredith Annex, Charles Blanchard, Cheryl Wilson	Natural Gas
Amy Grace, David Hostert, Stefan Linder, Stephen Munro, Aleksandra Rybczynska, Kieron Stopforth, Mark Taylor	Renewable Energy (Policy, Finance, Economics, Solar, Wind, Bioenergy, Geothermal, Hydropower) and CCS
Stephanie Adam, Albert Cheung, Ali Izadi-Najafabadi, Colin McKerracher, Thomas Rowlands-Rees, Shu Sun, Brian Warshay	Energy Smart Technologies (Combined heat and power, Fuel cells, Energy storage, Energy efficiency, Smart grid and demand response, Electric vehicles)
Nicole Aspinall, Joseph Salvatore	Economics and Finance

Copyright

© Bloomberg Finance L.P. 2014. Developed in partnership with The Business Council for Sustainable Energy. No portion of this document may be reproduced, scanned into an electronic system, distributed, publicly displayed or used as the basis of derivative works without attributing Bloomberg Finance L.P. and The Business Council for Sustainable Energy.

Disclaimer

This service is derived from selected public sources. Bloomberg Finance L.P. and its affiliates, in providing the service, believe that the information it uses comes from reliable sources, but do not guarantee the accuracy or completeness of this information, which is subject to change without notice, and nothing in this document shall be construed as such a guarantee. The statements in this service reflect the current judgment of the authors of the relevant articles or features, and do not necessarily reflect the opinion of Bloomberg Finance L.P., Bloomberg L.P. or any of their affiliates ("Bloomberg"). Bloomberg disclaims any liability arising from use of this document and/or its contents, and this service. Nothing herein shall constitute or be construed as an offering of financial instruments or as investment advice or recommendations by Bloomberg of an investment or other strategy (e.g., whether or not to "buy", "sell", or "hold" an investment). The information available through this service is not based on consideration of a subscriber's individual circumstances and should not be considered as information sufficient upon which to base an investment decision. BLOOMBERG, BLOOMBERG PROFESSIONAL, BLOOMBERG MARKETS, BLOOMBERG NEWS, BLOOMBERG ANYWHERE, BLOOMBERG TRADEBOOK, BLOOMBERG BONDTRADER, BLOOMBERG TELEVISION, BLOOMBERG RADIO, BLOOMBERG PRESS, BLOOMBERG.COM, BLOOMBERG NEW ENERGY FINANCE and NEW ENERGY FINANCE are trademarks and service marks of Bloomberg Finance L.P. or its subsidiaries.

This service is provided by Bloomberg Finance L.P. and its affiliates. The data contained within this document, its contents and/or this service do not express an opinion on the future or projected value of any financial instrument and are not research recommendations (i.e., recommendations as to whether or not to "buy", "sell", "hold", or to enter or not to enter into any other transaction involving any specific interest) or a recommendation as to an investment or other strategy. No aspect of this service is based on the consideration of a customer's individual circumstances. You should determine on your own whether you agree with the content of this document and any other data provided through this service. Employees involved in this service may hold positions in the companies covered by this service.