Coal Market Service

North America

May 2012

Executive summary[1]

Low natural gas prices have exposed the soft underbelly of coal procurement policies to the principle of "least cost dispatch". A glut in natural gas supply has forced gas prices low enough to out-compete coal at the busbar in almost every market in the immediate near term. This, in turn, has lead to a glut in thermal coal. Although we project a more balanced gas supply/demand picture to evolve from 2013 onward the new paradigm of coal/gas competition will linger keeping domestic coal prices in check. In the mid-term, natural gas prices climb slowly allowing for a related increase in coal demand and prices. Towards the end of the mid term a strengthening export market begins to turn the pricing dynamics away from natural gas and towards the international markets. Beyond 2020, exports increase rapidly to the point of dominating coal pricing. As a result, higher coal prices influence a shift away from coal and towards natural gas in the domestic energy markets, especially as we add a carbon tax from 2023 onwards.

Along the way, new environmental regulations for coal-fired generation will have some impact on coal prices. We are currently projecting that the Cross State Air Pollution Rule (CSAPR) will begin in 2014 and have relatively little impact on prices. Outside of some shift in Texas away from lignite to PRB coal we are not expecting coal procurement patterns to shift dramatically. The Mercury and Air Toxics Standards (MATS) will be the major factor that precipitates the retirement of 63 GWs of older coal fired plants by 2016. The resulting drop in coal demand, offset somewhat by increased operations at surviving coal units, causes prices to dip slightly in 2016.

The main underpinnings of our forecast are low natural gas prices in the near term, the MATS regulations in the mid term and high US thermal coal exports in the long term. We believe the risk of high gas prices is low given the long-term availability of plentiful low cost supply. MATS regulations are facing judicial challenges and the potential that subsequent government administrations may alter or rescind the rules – a moderate risk. Finally, while we believe the risk that Asia-Pacific economies will experience slow growth is low, the sheer magnitude of the potential energy demand in twenty years time is so large that there is a high risk of missing the level of eventual participation of the US in international markets.

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[1] We have reformatted the structure of our Long Term Outlook to make it more user friendly. The Assumptions section contains analysis and discussion on all key assumptions, from macro-economic, to electricity generation, emissions policy, and natural gas prices. The Regional Markets section contains all analysis and discussion on basin level market drivers. All spreadsheets are contained within the Data section. If you have any questions, please direct them to ellen.ewart@woodmac.com

Key issues

Key issues for the US coal market in our H1 2012 long-term outlook include:

Challenging compliance with upcoming environmental regulations: Environmental regulations on both coal-fired plant emissions and coal mining have raised the cost of coal-fired electricity in recent years. There have been several proposals for stricter environmental rules for the near future; which will continue to make coal generation less economic; including: Mercury and Air Toxics Standards (MATS), Cross-State Air Pollution Rule (CSAPR), Coal Combustion Residuals (CCR), Clean Water Act Section 316(b), Regional Haze Rule, and proposals to limit green house gas emissions (GHG). MATS is expected to have the largest impact on the coal market, effectively forcing unscrubbed coal units to add scrubbers or close – the major factor in influencing the 69 GW of coal-fired capacity that we anticipate to retire over the forecast period. Compliance with environmental regulations will cause dispatch costs for coal-fired generation to continue to rise and as a result, coal will face further competition from low-cost natural gas generation.

Persistently low natural gas prices: The natural gas market continues to struggle with over supply and storage issues that have driven prices further downward - below US$2/mmbtu - and has triggered wide scale displacement of coal-fired generation. Development of shale gas and the benefits of by-product gas from tight oil and gas liquids operations, has contributed to the over supply situation and is expected to keep prices low and stable throughout our forecast period. More favourable capital costs for new gas-fired generation – US$1,169/kW for a gas combined cycle (CC) versus US$3,675/kW for building a new conventional coal unit – will also work to incentivise more development of natural gas capacity over the forecast instead of new coal-fired generation.

Long-term US coal export growth: As the US domestic market for coal begins to decline, producers will look to the international market to fill the void in coal demand and, we project, find willing customers. Growing coal demand from developing countries – dominated by China and India – will boost global demand for seaborne thermal coal imports to 2.4 Bst by 2030 in our base case, nearly 3 times the current level. US exports, perennially the highest cost producer of international coal, will be limited in the near-term due to competition with new production from Australia, Colombia, Indonesia, Mongolia, Mozambique, and Russia. However, growing global coal import demand will eventually stretch supply enough to create an ever growing demand for US thermal coal in the last half of the forecast – growing to nearly 470 Mst by 2030. The key challenge for producers during those years will be expanding US coal export capacity enough to meet demand - with government approval for new ports as the major hurdle.. An additional hurdle for investing in new port capacity, is that the US role in the international coal market will likely be very volatile. Any alteration in the development of Asian economies or rate at which other coal producing nations respond to the increasing demand could have a dramatic impact on projections for US competitiveness in the global markets.

Competition between basins: Rising production costs in CAPP will influence more switching away to lower cost ILB coal over the forecast – especially with less reliance on low-sulphur coal over time. When our expectations for the CSAPR rule take effect in 2014, lignite regions will begin to lose some market share to lower sulphur PRB coal. Low cost PRB coal will gain the largest portion of the coal export market as more port capacity is built on the US west coast. ILB will also grow to capture a significant portion of the export market as well, with more export capacity being developed in the Gulf and its structurally lower cost advantages over other US bituminous coals.

Price summary

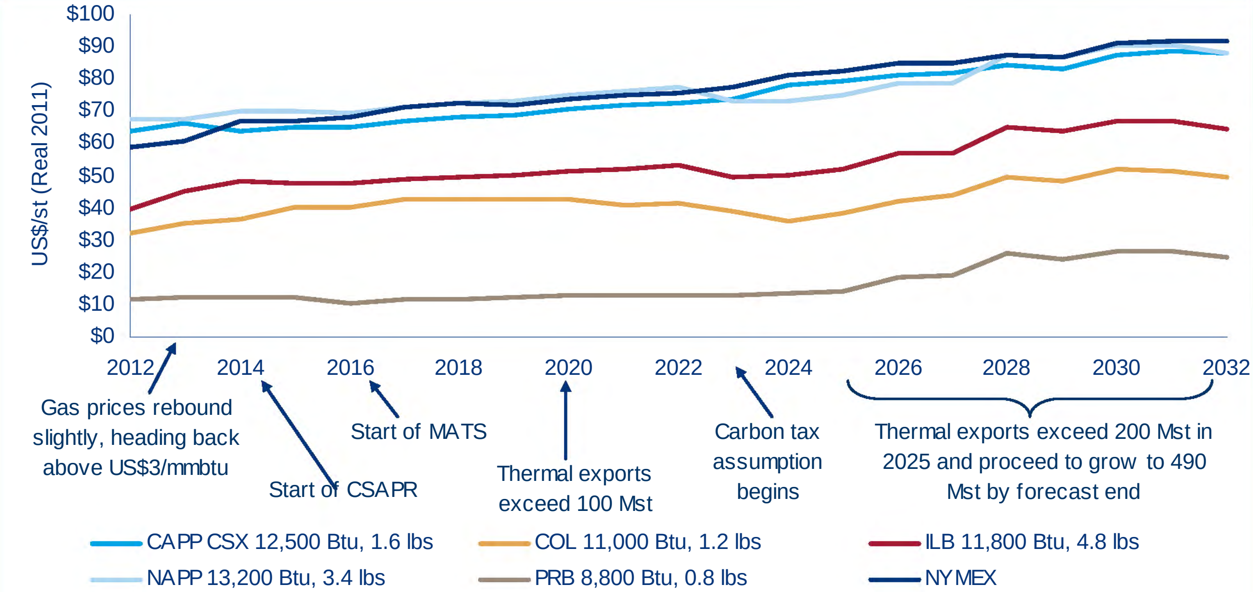
The production of electricity is one of the most elastic and competitive markets in the US. Every minute of every day individual generating units are dispatched by control rooms across the nation on the principle of least cost generation - with least cost generation essentially defined by a units fuel cost and efficiency at turning that fuel into electricity. In most years the relative low cost of coal compared to natural gas has lead to expectations of stable, base load, coal demand and volatile natural gas demand to fill in during spikes in electrical demand. The development of shale gas has turned that paradigm on its head. In late 2011 and into 2012 an overabundance of natural gas supply has needed to find a market. Industrial and residential use of gas is relatively inelastic over the short term and, after gas storage options were exhausted, gas prices began to reflect levels needed to “displace” coal in terms of least cost generation.

The result is a disaster for coal demand in 2012. The lack of transparency in coal prices and the historically predictable levels of coal burn have led to policies that tend to fix coal prices over one- to five-year periods for a large proportion of requirements. In order to influence more demand for natural gas, gas prices dropped low enough to let the economics of least cost dispatch favour the choice of gas units before coal units to meet electricity demand. The problem has been exacerbated by a historically mild winter that has reduced electricity demand dramatically from normal levels. The implication for prices is that any coal contracts negotiated in 2012 and beyond will have to be low enough priced to out-compete natural gas at the busbar. For 2012, this means very low prices. Between 2013 and 2014, we expect that an increase in electricity demand and a more balanced supply/demand balance in the natural gas market will lead to a recovery in coal demand and prices. However, there is a risk that high coal stockpile levels will hinder price recovery during that period.

In the mid term, natural gas demand and prices climb slowly as coal is displaced in basins with higher costs allowing for a related increase in coal prices. Towards the end of the mid term a strengthening export market begins to turn the pricing dynamics away from natural gas and more towards the international markets. In the long term, after 2020, exports increase rapidly to the point of dominating coal pricing. As a result, higher coal prices influence a shift away from coal demand domestically, especially as we add a carbon tax from 2023 onwards.

Along the way, new environmental regulations for coal-fired generation will have some impact on coal prices. We are currently projecting that the Cross State Air Pollution Rule (CSAPR) will begin in 2014 and have relatively little impact on prices. Outside of some shift in Texas away from lignite to PRB we are not expecting coal procurement patterns to shift dramatically. The Mercury and Air Toxics Standards (MATS) will be the major factor that precipitates the retirement of 63 GWs of older coal fired plants by 2016. The resulting drop in coal demand, offset somewhat by increased operations at surviving coal units, causes prices to dip slightly in 2016.

Market coal price forecast factors (Real 2011 US$)



Source: Wood Mackenzie Coal Market Service
Note: Except for NYMEX, all prices are FOB mine.

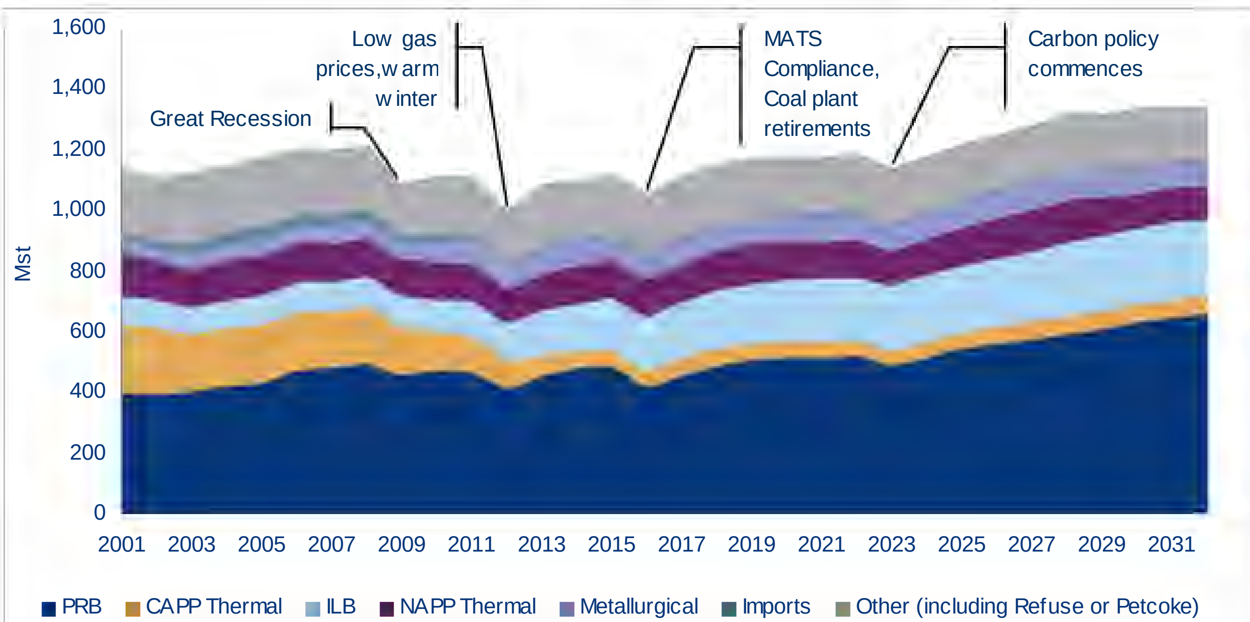
Key market data

US supply/demand balance (Mst)

	2011A	2012	2013	2014	2015	2020	2025	2030
Supply (Mst)	**1,114.2**	**998.5**	**1,083.4**	**1,096.7**	**1,119.9**	**1,179.6**	**1,218.0**	**1,335.0**
PRB	467.3	408.4	453.9	481.1	487.7	511.2	544.0	632.7
CAPP Thermal	120.6	88.7	70.5	54.3	55.2	53.5	55.4	61.4
ILB	116.7	127.1	144.1	157.2	167.4	208.0	218.8	250.3
NAPP Thermal	118.6	111.9	121.7	124.5	126.8	122.1	122.4	108.8
Metallurgical	86.8	85.2	84.9	85.5	86.7	88.3	90.9	87.0
Imports	12.0	8.9	6.7	3.5	4.4	5.3	5.2	5.1
Other (including Refuse or Petcoke)	192.2	168.3	201.6	190.6	191.7	191.2	181.3	189.7
Demand (Mst)	**1,114.2**	**998.5**	**1,083.4**	**1,096.7**	**1,119.9**	**1,179.6**	**1,218.0**	**1,335.0**
Electricity Generation	931.4	805.4	923.9	940.7	952.2	946.7	873.1	725.0
Industrial	53.9	47.7	49.1	51.7	52.0	52.9	53.8	54.4
Thermal Export	41.8	44.3	38.5	31.3	29.0	91.7	200.2	468.7
Metallurgical Demand	86.8	85.2	84.9	85.5	86.7	88.3	90.9	87.0
Stockpile Increase (decrease)	0.2	16.0	-13.0	-12.5	0.0	0.0	0.0	0.0
CAPP 12,500 btu 1.6#SO2 CSX price (2011 US$/short ton)	$75.17	$64.26	$66.40	$64.13	$65.10	$70.75	$79.23	$87.82
NAPP 13,200 btu 3.4#SO2 price (2011 US$/short ton)	$77.25	$67.81	$67.82	$70.48	$70.35	$75.08	$74.99	$90.59
ILB 11,800 btu 4.8#SO2 price (2011 US$/short ton)	$51.34	$39.77	$45.11	$48.61	$48.07	$51.57	$52.17	$67.28
PRB 8,800 btu 0.8#SO2 price (2011 US$/short ton)	$13.61	$12.02	$12.47	$12.35	$12.46	$12.95	$14.29	$26.88
Henry Hub natural gas price (2011 US$/mmbtu)	$4.00	$2.62	$3.80	$4.00	$4.23	$5.54	$5.95	$6.00

Sources: EIA, MSHA, Wood Mackenzie Coal Market Service

US thermal coal supply outlook (Mst)



Source: Wood Mackenzie Coal Market Service

Market implications

Real paradigm shift – the market is not going back to the way it was

The coal market is in the midst of several paradigm shifts that will work through during the next 20 years. Arguably the first of the paradigm shifts, **intensive emissions restrictions on coal plants**, has been under way since the passage of the Clean Air Act in 1970. And also arguably, the manifestation of the paradigm shift that the US Energy industry is facing – namely the near simultaneous retirement of 69 GWs of coal fired generation – could have been avoided or at least spread out over dozens of years. The intention of the Clean Air act was that older coal fired units should be phased out to be replaced by new clean units. However, the unintended consequences of the law were that compliance with the "New Source Performance" regulations turned out to be much more expensive than nursing along the older units which were initially grandfathered under relaxed emissions standards. Meanwhile the timetable for additional emissions regulations, and compliance, as laid out in the Act began to drag out for a variety of bureaucratic, political and economic reasons. The situation that the industry is now faced with has been, perhaps, inevitable, only waiting for an Administration with a strong environmental motivation – and energy industry stakeholders, including politicians, ratepayers and utility commissions that have explicitly or implicitly contributed to clean-up delays may now have to face an expensive, shortened compliance timeframe.

Coincidentally, the impact of environmental regulations in terms of plant retirements has been magnified by the advent of the second paradigm shift: **the prospect of abundant, low cost natural gas**. The development of the technology to extract natural gas and other hydrocarbons trapped in shale layers is truly a game changer. As little as five years ago the expectation of high natural gas prices from a dwindling conventional gas reserve base stimulated a plethora of planned coal-fired capacity expansions – both to meet expected load growth and to finally begin replacing older, dirtier capacity. The recession notwithstanding, shale gas has put an end to those plans and subsequently has made the economics of spending billions of dollars to clean-up the remaining unscrubbed portion of the coal fleet perilous as well. In the near term, natural gas is just plain less expensive than coal leading to a complete shake-up in the dispatch of plants to meet electricity demand and providing coal producers with a clear lesson in the meaning of the term "least cost dispatch".

The third paradigm shift is under way but the major impact on the US coal market is, for the most part, still in the future. The International Energy Agency has reported that as of 2009, as many as 675 million people in Asia do not have electricity. The prospect of raising the standard of living for that many people is daunting when one considers the energy and commodities required. We believe that even including greatly increased domestic coal production as well as increased production from existing coal exporting nations such as Australia and Indonesia there will, eventually be **an opportunity for the US, the perennial swing supplier to the international thermal coal market, to play a major role**. However, the massive size of the market is also a major source of uncertainty for US suppliers. As the supplier with the highest cost basis of any of the major exporting nations, the US will be the first to be dropped if demand falters and the focus of intense pressure when demand increases. And the potential swing in demand is daunting – total current US thermal coal exports (42 Mst in 2011) barely exceeds four days burn of coal in China alone. Any number of uncertainties, from misjudged economic projections to environmental concerns to unforeseen political unrest could alter demand projections by hundreds of millions of short tons per year – or even year to year – a figure that in itself nearly exceeds the current capacity of bulk export facilities of the US. The lack of exporting facilities, especially off the US west coast also adds uncertainty to a market struggling with a future so different from the past.

A fourth paradigm shift that has been under way since the late 1990s is the **decline of Central Appalachia as a source of thermal coal**. Since 2001 CAPP thermal coal production has dropped from 231 Mstpa to 121 Mstpa in 2011. The cost of mining CAPP coal is just too expensive, with thinning seams, costly permitting delays, and a cultural change in operational safety, compared to alternate coal basins and, now, natural gas.

To summarize: US coal producers face an immediate challenge to demand and price from natural gas. Mid-term, while natural gas is less of a day-to-day threat, except for high cost CAPP coal, the imposition of strict emissions requirements will retire coal-fired plants currently consuming up to 140 Mstpa of the thermal coal. Longer-term a massive opportunity to participate in international markets holds out hope, and uncertainty, for coal producers and owners of bulk export facilities. On the other hand, coal buyers find themselves over-committed to coal in the near term and in the mid term must choose between switching to natural gas or refurbishing older coal-fired plants to meet strict new emissions regulations. Nominal buyers of CAPP coal must decide whether to continue with the most expensive thermal coal in the country or make the necessary adjustments to burn other coals or switch to gas-fired generation. Longer term, buyers must compete with an ever growing and potentially volatile international coal market.

So what's a producer to do?

Thermal coal mining in the US is a competitive and rarely a high margin business. So rare, in fact, that we project prices – we believe with some success – based on the marginal cost of production. So, in a market in which buyers have low cost alternatives, **minimizing production costs is essential**. The cost of coal mining is directly related to productivity and mine productivity, itself, is related to the geological conditions of the mine. Producers will seek to avoid or put off mining in areas with unfavourable geology. However, in many cases this will mean idling or closing higher cost operations. Producers will consolidate operations by moving their most skilled workers and best mining equipment to the reserves with the most favourable geology.

Producers will also seek to improve the efficiency of their coal processing facilities. Coal processing facilities generally use gravimetric processes to separate heavier, non-coal, mineral matter from the valuable coal. The separation ability of the process is rarely 100% efficient and coal is discarded along with the mineral matter to a greater or lesser degree depending on a host of variables. These are often highly related to the quality level desired in the cleaned product with the efficiency degrading more rapidly as the quality of the final product increases. This means that coal producers may be able to offer lower quality products at a discount, even in terms of $/mmbtu, compared to their higher quality products.

Producers should not by shy to idle mining operations if economically and operationally possible. Currently there is a glut of natural gas due to over exuberant leasing activities and continued improvements in extraction technology. Until the natural gas market supply is more in balance with demand, natural gas will continue to be priced competitively with coal. Any coal delivered into the current market just delays the day when gas prices can return to a more balanced condition rather than one determined by the need to place superfluous volume into the market.

Perhaps a point that may have been missed by coal suppliers early on is just how the principles of least cost dispatch create an extremely efficient market for the operation of electricity generating units (EGUs). Just cents per MWh difference in generating cost may mean the difference between operating full load or minimum load. The fungibility/transparency in natural gas prices means that gas prices, and gas-fired generating costs, can fluctuate daily to adjust to market conditions. Unlike gas prices, delivered coal prices at EGUs are much less responsive to market conditions and are definitely not as transparent. Essentially every individual EGU functions as a clearing hub for coal prices. The need to maintain and control coal supply security and quality and to eke every price advantage out of the market place has lead to a system of privately negotiated, confidential, take or pay contracts usually initiated by a Request for Proposal process months, or even years, in advance of deliveries. Prices and volumes are often set for many months, or years forward. While this process has its advantages when purchasing a non-homogeneous product like coal and dealing with counterparties with varying creditworthiness and performance history, it has the distinct disadvantage of being unable to respond quickly to competition at the busbar. The very day, if not hour, that gas prices drop low enough to make gas-fired generation cheaper than coal – and which prices are readily discernable due to the transparency of the gas market - the coal unit backs down. Coal, on the other hand, essentially has a fixed price in the near term and clearly the response of coal producers and buyers to the sudden drop in coal demand has taken months to even begin to work through even when coal was clearly disadvantaged. The implication for both producers and buyers is that **more effective price transparency and hedging tools are needed for the coal market**.

Vertical integration, that is, coal producers owning and operating generating plants, is a possibility but only if gas units are included in the stable of generating assets or in certain special circumstances where a known, very low cost reserve, can be linked to a generating unit. Few coal producers have the financial strength or reserve position to pursue this strategy. However, more producers may be able to adopt "virtual" vertical integration by using the natural gas and power financial markets. For instance a producer could buy a put on natural gas such that if gas prices move low enough to reduce coal-fired operations at his customers EGUs then a portion of his profit will be protected even if coal is not shipped. Producers could also vertically integrate into the transportation and export business. Owning or controlling port capacity, and/or the means to access ports, can mean the difference between participating in international markets or sitting on the sidelines.

Diversification is another opportunity for producers. Several paths are available. Profit margins on metallurgical coal remain strong. Many coal producers own mineral and gas rights in the Marcellus and Utica shales. Developing export business will also pay dividends in the future. A more risky proposition and one that may take years to bear fruit would be to invest directly in export infrastructure.

Mergers and acquisition are likely as producers find it expedient to have sufficient diversification and production options, not to mention stronger balance sheets, to weather a market very likely to experience much higher volume, if not price, volatility.

How will buyers react?

Operators of EGUs find themselves in a world where coal and gas are competitive at the busbar. Not only that but the recession of 2009 showed that the even forecasting total demand can be far enough off to require a change in the standard way – long term physical contracts – of hedging coal price and supply availability. Absent a short term transparent pricing mechanism for coal it would seem that **coal contracts need to be either very low cost or very flexible and, preferably, bot**h. Producers from the ILB, PRB and, to some extent, NAPP probably can accommodate this trend – partly because the inherent lower cost basis of these regions makes them somewhat less susceptible to gas competition. However, EGUs dependant on CAPP coal are in a more difficult position. The high cost of CAPP coal makes it very susceptible to gas prices or replacement by less expensive coals – for those EGUs that can switch – which in turn means that demand will be volatile and likely shrinking. As a result, security of supply may become a major issue for plants that are operationally restricted to use CAPP coal.

In this instance, regulated EGUs must weigh the value of fuel diversity over a long period of time as, in our view, we do not believe that natural gas prices will soon return to levels at which the price of CAPP coal delivered to EGUs will be consistently competitive. EGU operators may have to continue to commit to long term high priced coal contracts in order to maintain security of supply in a basin whose market share is naturally shrinking. Another possibility is **vertical integration by owning/operating coal assets**. This has been tried in the past with generally poor results but, because of the lessons learned, may be an option going forward.

Unregulated EGU operators will seek to **close unprofitable coal capacity** with this decision made easier due to the heavy capital requirements for environmental compliance. Brownfield development of new gas-fired capacity on the site of retired coal plants is a distinct possibility but announcements for this type of development may have to wait for the impact of the coal retirements to work through the capacity market systems of the various RTOs before the economics become compelling.

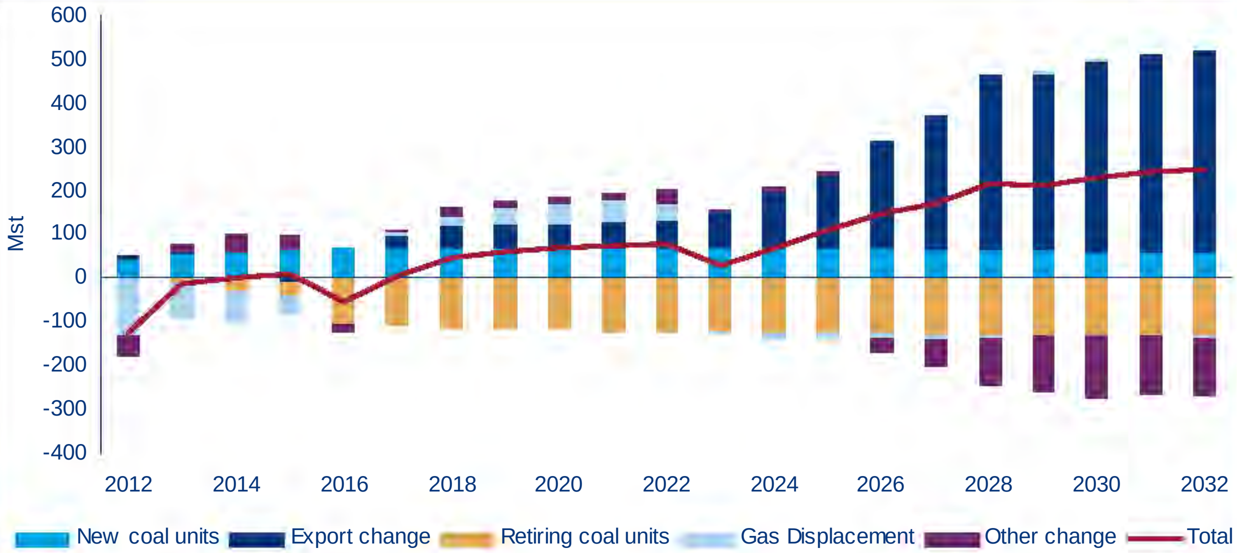
Unregulated coal-fired EGU operators also have options to **hedge coal plant operations in the power and gas financial markets**. Because many coal producers lack the expertise or balance sheet to cover their physical risks with financial hedges the possibility exists for risk sharing partnerships between EGU operators and coal producers.

Railroad response

Railroads, too, have had to deal with the realities of least cost dispatch policies. Although coal under current contract – which also means with rail contracts as well – is being delivered or deferred, it is now clear **that more flexibility in controlling coal volume is necessary on the buyers end and that margins on transportation contracts now must consider the competitiveness of natural gas generation as well as alternate fuel transportation options**. The railroads are left with the problem of protecting margins on routes where it is likely that less coal will move under contract and perhaps less coal altogether. Raising rates may be self defeating as that will just make the coal less competitive versus natural gas. An option, where it is clear that gas and coal are competitive would be to hedge with natural gas financial instruments.

Railroads have a lot of control over the competitiveness of US coal overseas as well. Railroads long term interest would seem to be served by helping to ensure that US coal can compete in international markets. Besides careful rate design participation in the development of bulk export facilities may be a worthwhile investment.

US thermal coal demand growth*



Source: Wood Mackenzie Coal Market Service
**Other changes include reduced operations at existing units due to additions of new gas and/or renewable capacity as well as the impact of carbon taxes*

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