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Carbon capture and storage at scale: Lessons from the growth of analogous energy technologies

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ABSTRACT

At present carbon capture and storage (CCS) is very expensive and its performance is highly uncertain at the scale of commercial power plants. Such challenges to deployment, though, are not new to students of technological change. Several successful technologies, including energy technologies, have faced similar challenges as CCS faces now. To draw lessons for the CCS industry from the history of other energy technologies that, as with CCS today, were risky and expensive early in their commercial development, we have analyzed the development of the US nuclear-power industry, the US SO_2-scrubber industry, and the global liquefied natural gas (LNG) industry. Through analyzing the development of the analogous industries we arrive at three principal observations. First, government played a decisive role in the development of all of these analogous technologies. Second, diffusion of these technologies beyond the early demonstration and niche projects hinged on the credibility of incentives for industry to invest in commercial-scale projects. Third, the conventional wisdom that experience with technologies inevitably reduces costs does not necessarily hold. Risky and capital-intensive technologies may be particularly vulnerable to diffusion without accompanying reductions in cost.

1. Introduction

In the last few years, the potential for capturing and storing carbon dioxide in deep geological formations has received widespread attention. And rightly so—carbon capture and storage (CCS) is among the options with great potential to combat climate change through reduction of CO_2 emissions. According to the PRISM analysis, a technology assessment performed by the Electric Power Research Institute (EPRI), wide deployment of CCS after 2020 in the US power sector alone could reduce emissions by approximately 350 million tonnes of CO_2 per year (Mt CO_2/yr) by 2030 (EPRI, 2007). Other studies echo these conclusions (McKinsey, 2007). To put this number in perspective, the Kyoto Protocol CO_2 emissions reductions target for the European Union (EU-25) is 340 Mt CO_2/yr below the expected level on average during the five year "commitment period" from 2008 to 2012 (EEA, 2006). Expectations for CCS are huge.

But building CCS into such a formidable element for climate change mitigation will require more than technological feasibility. It will also require the development of regulatory and incentive policies to support business models that can enable wide adoption. As the policies currently in place are generally inadequate, such business models have as yet been largely undemonstrated. Consequently, the number of current real CCS projects is small, because the projects that are most likely to be pursued today are those for which "one-off" factors, such as the prospect of public subsidies, play a dominant role. The most likely projects today are those in "ideal" circumstances—such as power plants that sit adjacent to large demands for CO_2 for enhanced-oil-recovery (EOR) operations—that are not sufficiently common to support a full-scale industry that would store hundreds of millions of tonnes of CO_2 annually (Rai et al., 2008).

2. Scope of this paper

As the experience of today's emerging CCS industry bears only partial resemblance to a possible full-scale commercial CCS industry in the future, this paper searches for insight on the likely development path of CCS by exploring analogs from the emergence of other energy technologies. We concentrate on industries that, at their origins, faced obstacles that were similar to those in the CCS industry today—namely, extremely high capital intensity and infrastructure dependence, an uncertain revenue stream that depends on regulatory decisions, uncertainties about the technology's performance and the regulatory

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context at scale, and a complex value-chain needing collective action from relevant parties. Although we draw from the experience of other technologies, our analysis focuses mainly on the historical experience of three technologies:

- The deployment of nuclear power, especially in the United States.
- The emergence of an infrastructure and market for delivery of liquefied natural gas (LNG).
- The deployment of SO_2-scrubbing (flue gas desulphurization or FGD) technology in the US.

Through exploring these relevant analogs to the CCS industry, we will focus on answering the questions below:

- What were the pivotal regulatory and policy decisions that drove initial innovations in and demonstration of these technologies?
- How was the commercial risk associated with deployment reduced to enable wider diffusion of the technology in the market space?
- What was the learning curve for cost reduction as these technologies diffused more widely?

We infer lessons about the likely adoption trajectories for CCS, which is currently at a very early stage of deployment and faces analogous hurdles before it can be applied on a widespread basis. We also draw insights into the policies that will be necessary to foster commercial-scale deployment of CCS. We hope that this work will spur dialogue on the viability and timetable for the emergence of a full-fledged CCS industry.

3. Challenges in scaling up the CCS industry

We started our analysis by identifying the main obstacles to the scaling up and widespread deployment of CCS. Those obstacles have been discussed widely in the literature (IPCC, 2006; McKinsey, 2008; WRI, 2008; GCCSI, 2009) and center on four in particular: (a) extremely high capital intensity of fully developed CCS projects; (b) uncertain revenue stream owing to the lack of reliable and sufficiently high pricing for CO_2 abatement; (c) huge uncertainties in regulation and technical performance; and (d) a complex value-chain that multiplies risks and uncertainties across the whole series of activities that together comprise a viable CCS project. Having identified these four obstacles, early in our study we presented our framework at industry conferences and with CCS project developers to ensure that we had identified the right short list of major challenges. In the next four paragraphs we discuss them in more detail.

Including CCS in a project is extremely costly. For example, capital costs are projected to increase nearly 50% for coal power plants with CCS compared with the non-CCS option (McKinsey, 2008). The cost increase is expected to be more acute for early commercial projects: for early projects subsidy/grant requirements may be as high at $1 billion for a 900 MW coal power plant (McKinsey, 2008). High capital expenditure usually means a longer-than-normal time horizon over which the project must generate positive cash flows to become commercially viable. For new technologies with unproven track record, guaranteeing such income streams over long periods is difficult, especially when uncertainties run high on almost all fronts—requirement of large capital investments in CCS projects presents a major hurdle.

Lack of inherent value of CO_2 (as opposed to nuclear power or LNG) makes revenue streams from CCS projects dependent on regulatory actions. On the basis of avoided emissions, the cost of CCS ranges from $30 to $90/tonnes CO_2 (IPCC, 2006; McKinsey, 2008; Rubin et al., 2007), which translates into a 60–80% increase in the levelized cost of electricity ($/MWh) (Dalton, 2008). At the end of the day somebody has to pay for the high-cost electricity so that commercial entities are profitable enough to attract continued investment. Typically, in other settings, the demand for high-cost electricity is created through policy incentives such as mandatory renewables portfolio standards (RPS) as in many states in the United States and feed-in-tariffs (FIT) for electricity from renewable energy sources as in Germany. But no such demand pull schemes yet exist for CCS. Putting a price on carbon, though a necessary step, will not be enough to attract the necessary scale of investments in CCS. It is not surprising, then, that most CCS projects under operation or with a high probability of successful development depend on special circumstances that do not yet readily apply at broad scale. These include special government policies (e.g., Norway's carbon tax, which incentivizes CO_2 storage) and, notably, the special opportunity for EOR where fields are mature and oil prices are high. Until a credible scheme is in place to ensure cost recovery more broadly, other projects are excessively risky to undertake.

The technological and regulatory uncertainties associated with CCS scale-up are also high. Although there is considerable experience in capturing CO_2 in the chemicals industry and the natural-gas processing industry, technology and operational experience is virtually nil for CCS from power plants. The dearth of experience makes cost and performance predictions extremely difficult, contributing to major uncertainty around the long-term viability of investments in the technology. Scaling up CCS volumes will also require a regulatory regime to govern injection of the captured CO_2 underground. That the US Environmental Protection Agency (EPA) proposed regulations for injection wells for non-EOR-related CO_2 only in July 2008 (EPA, 2008) is just one indication that the regulatory process for CCS, much like the CCS industry itself, is in the early stages of development. More generally, the relevant regulatory framework is highly fragmented across the permitting process at different steps of the CCS value chain: capture (utility commissions regulating power plants), transport (FERC but also state bodies), and storage and monitoring (EPA). Over time, advances in technology and regulation, respectively, will mutually reinforce progress in the other, and the associated uncertainties will reduce. For the moment, uncertainties in regulatory regimes and technological capabilities appear to yield a stalemate: unless something significantly reduces the uncertainty in one area (say, legislation mandating CCS or a breakthrough in the CO_2 capture process), the other has little incentive to move forward.

Yet another key obstacle in scaling up CCS is the complex value-chain of CCS, which requires collective action of commercial entities with very different risk attitudes. For example, in the US the power generation business is dominated by risk-averse regulated utilities, while much of the knowledge about geological storage is held by major oil companies that thrive on risk. Such diversity in the risk attitudes of players in the same value chain can lead to investment deadlocks, as the partners across the value chain find it difficult to manage co-dependent commercial risk. CCS has not reached a stage yet where the ability of the CCS industry to organize at scale in different geographical and regulatory contexts has been tested, but the relevant players are well aware that the complexity of the CCS value chain could be a thorny issue to sort out at scale.

Obviously there are other obstacles that technologies often face. Among those is public opinion. Some CCS projects, even at these early stages, face opposition from land owners and neighbors who fear injection of CO_2 under their backyards. So far, such problems appear to be relatively isolated and are comparable with siting troubles that arise for other large industrial plants and not (yet) as acute as the siting problems that have confronted the nuclear power industry. In this paper, we set such concerns aside, not least because these siting difficulties do not appear to be nearly as challenging as the problems of carrying the technology to a stage where it is commercially viable.

4. Selection of industrial analogs to CCS

As mentioned above, we have chosen to analyze the development of the nuclear power, LNG, and SO_2-scrubber industries. Table 1 shows how the challenges of each of these industries in their infancy compared with the present obstacles facing the CCS industry. Both LNG and nuclear power projects are very capital intensive, and project costs often reach billions of dollars. Like CCS, the value chain for these two industries also involves several players who coordinate complex activities. For LNG the value chain includes gas production, liquefaction, sea transport, regasification, and supply to consumers. For nuclear power, in addition to the usual steps in power generation and supply, the value chain involves fuel mining and processing, and waste handling and disposal. CCS faces a choice between possible technologies whose relative merits have not yet been evaluated at scale. Similar technology uncertainty was encountered for nuclear reactors (pressurized water or boiling water reactors) and SO_2 scrubbers (wet or dry scrubbers, pre- or post-combustion scrubbers). Although SO_2 scrubbers are a lot less expensive than CCS, the development of the SO_2-scrubber industry shares one significant attribute with the CCS industry that the other two selected analogs do not: for both the SO_2-scrubber industry and the CCS industry, the inherent market value of the substance being processed—SO_2 for the SO_2-scrubber industry and CO_2 for the CCS industry—is negligible (leaving aside the CO_2-EOR niche). In both cases, unlike LNG and nuclear power, commercial value for the technology is created by regulation. Because of this unique similarity, the SO_2-scrubber industry may add important insight to the picture of how CCS might evolve. Finally, in both nuclear and CCS industries large liabilities may arise in the event of a major accident.

5. Achieving scale: stages of technology development

The classic *S*-curve description of a technology lifecycle (Fig. 1) posits that a new technology goes through a phase of innovation in which it is first demonstrated and embraced by early adopters, followed by one of diffusion as awareness of the technology penetrates throughout the potential market space, and finally maturity as the technology saturates its natural market.

Fig. 2 shows actual technology adoption curves for the three analogs to CCS that we are considering in this paper. On these curves, we identify the three most salient phases in the deployment of these kinds of technologies. First, there is the technology demonstration period in which the new technology is deployed and shown to work in a limited segment (niche) of the potential market. Second, there is the diffusion phase, when methods are found to sufficiently reduce the business risk of large-scale, commercial applications to allow at least a limited number of such projects to go forward. For the analogs discussed here and CCS (complex, capital-intensive, and risky from a financial and regulatory perspective) the diffusion phase is mostly about reducing financial risk: the barrier to diffusion is less a lack of awareness of the technology than insufficient demonstration that businesses implementing the new technology can reliably do so profitably. The increase in the technology's market penetration during this phase is (ideally) associated with decreasing implementation costs from experience. Third, there is the period of maturity in which a business model proven to be broadly viable encourage the technology to spread in a self-sustaining way until it hits fundamental limitations to its growth (e.g., the available geological storage potential, in the case of CCS).

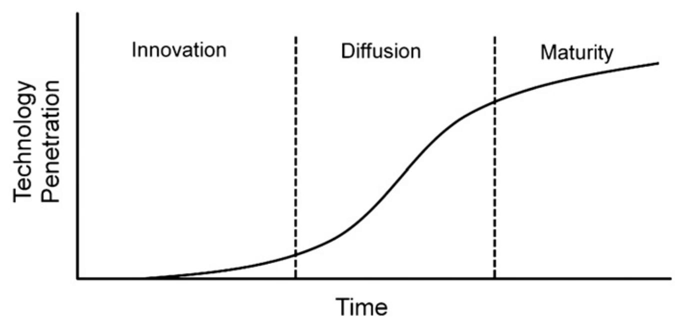

Fig. 1. Stylized "*S*-curve" of technology diffusion.

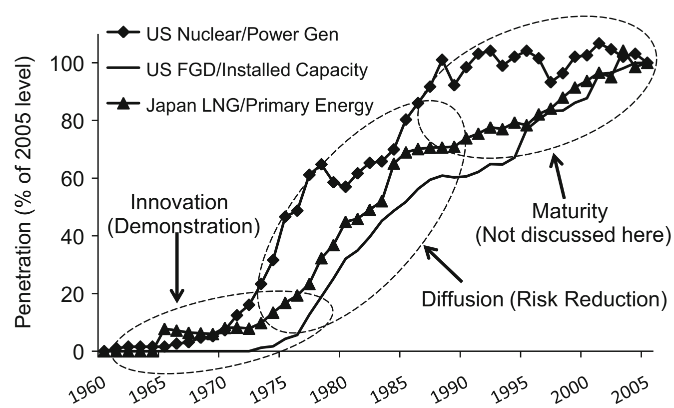

Fig. 2. Growth of market-share penetration of technologies. Market share in 2005 is assigned an index equal to 100. Calculation of market share: US nuclear power as percent of total US power generation; US FGD capacity as percent of US coal-based installed capacity; LNG consumption in Japan as percent of Japanese primary-energy consumption. *Data source*: BP (2008), EIA (2007a), and Taylor et al. (2005).

Table 1
Comparison of the attributes of the CCS industry at present with other industries at the time of their early development.

	Nuclear power	LNG	SO_2 scrubbers
Huge capital investment	Yes	Yes	Maybe
Inherent value	High	High	For SO_2: low
Technology uncertainty	Yes	Maybe	Yes
Complex value chain	Yes	Yes	No
Potentially large liability	Yes	Maybe	No
	Yes/Low: Attribute similar to CCS	No/High: Attribute different from CCS	Maybe: Attribute's analogy to CCS depends

In reality, of course, there is some fluidity among these three phases, and aspects of more than one may be seen at the same time.

At present, CCS remains in the period of technology demonstration, with aspects of the technology partially demonstrated (e.g., carbon storage in depleted oil and gas fields) and others still largely unproven (e.g., carbon capture at large scale after fossil fuel combustion). In the remainder of this paper, we will examine the history of the three analogous technologies in the first two of the three major phases in a technology's development, namely in the technology demonstration phase and in the diffusion phase. We will not, here, examine possible full maturity of these technologies. Finally, we will consider the lessons that may be drawn for CCS.

6. Technology innovation and demonstration

The technology validation stage is about both R&D to develop key technological building blocks and also critically the creation of markets in which the technology can be deployed and proven. Frequently, these nascent markets involve either special support that would not be available at a more commercial stage of development, or they are centered on particular, limited applications (niches). For the kinds of risky, capital-intensive technologies considered here, some kind of government strategic interest often drives and supports early technology validation efforts. However, there are cases in which business motives alone can spur creation of niche markets that help validate technologies. The optimal conditions for a technology's validation exist when the strategic interests of government and businesses align (CO_2-EOR is a good example, which we discuss later).

6.1. SO_2 scrubbers

The US Department of Health, Education, and Welfare (HEW) started supporting research activities in SO_2-control technologies as early as the 1950s. The 1967 Air Quality Control Act and the 1970 Clean Air Act Amendments further augmented federal support for R&D in this area; public R&D expenditure on SO_2 stood at over $300 million (2003$) before the New Source Performance Standards (NSPS) of 1979 came into act (Taylor et al., 2005). These laws also, for the first time, established clear demand signals for SO_2-control technologies, leading to the acceleration of commercial patenting activity. The NSPS established in 1971 limited emissions to 1.2 lbs SO_2/mmbtu (2.2 kg/Gcal) heat input to the boiler for new and substantially modified sources (Rubin et al., 2004). Depending on the properties of the coal, these standards could require up to 85% removal of SO_2 from flue gases. As this performance-based standard afforded technological flexibility, coal power plants responded by using either pre-combustion or post-combustion SO_2-control technologies, depending on the type of coal they used (low-sulphur or high-sulphur). Clearly, for SO_2 emissions control in the US the federal government and its agencies provided basic R&D support to kick-start the efforts, and ultimately also provided the legislative and regulatory support that helped create a market for SO_2-control technologies.

6.2. US nuclear power industry

The government played the leading role in starting the nuclear power industry as well, with even more vigorous support than in the SO_2 scrubber case. In light of the decisive role that the nuclear technology of the atomic bomb played in World War II, governments in developed countries, especially in the US, the UK, France, West Germany, Sweden, and Japan, placed enormous strategic value on the rapid development of nuclear technology (Campbell, 1988; Hecht, 1998). The emphasis was not only on military power; these governments also quickly recognized the tremendous potential of nuclear electric power. The hurry to promote and develop nuclear power generation was so great that these governments came up with comprehensive national policies for atomic energy, all within a few years around 1950 (Fig. 3)—the US in 1946 and 1954, the UK in 1954, France in 1945, Germany in 1960, and Sweden and Japan in 1955. Billions of dollars of public money flowed to support basic R&D work (Campbell, 1988; Hecht, 1998; Patterson, 1986). Additionally, reprocessing technologies developed through defense funding were transferred to the private sector as an additional spur to progress (Campbell, 1988; Hecht, 1998; Patterson, 1986). With governments firmly behind it, the stage was set for the rise of nuclear power—a classic example of government-led technology validation.

6.3. LNG

In 1970 oil formed 71% and coal formed 13% of Japan's primary energy consumption. By the late 1960s as Japanese energy policy began emphasizing energy security (through fuel diversity) and cleaner fuel, Japan looked to gas as an attractive option. The oil shock in 1970s reaffirmed to Japan the wisdom of diversifying away from oil. Incidentally, large volumes of gas were discovered in Indonesia and Malaysia around the same time. These events led Japan to strongly orient its energy policy in favor of LNG imports (Ball et al., 2004). Japan, given its extraordinary interest in LNG, essentially underwrote the entire risk in big LNG projects, like the Arun Project with Indonesia and the Das Island imports from Abu Dhabi (UAE). Its appetite was so strong that the agreements for LNG from Arun signed in 1973 between five Japanese companies and Indonesia covered all LNG exports from Arun and its sister project Bontang. The initial plan was only for 40% LNG from Arun to find its way to Japan. Much of the funds for the development and expansion of these projects ($3.6 billion in 2005 dollars for the Arun plant in 1973–1974) were either directly provided by the Japanese, or had their significant underwriting. At home, Japanese utilities were permitted to pass on the LNG costs to the

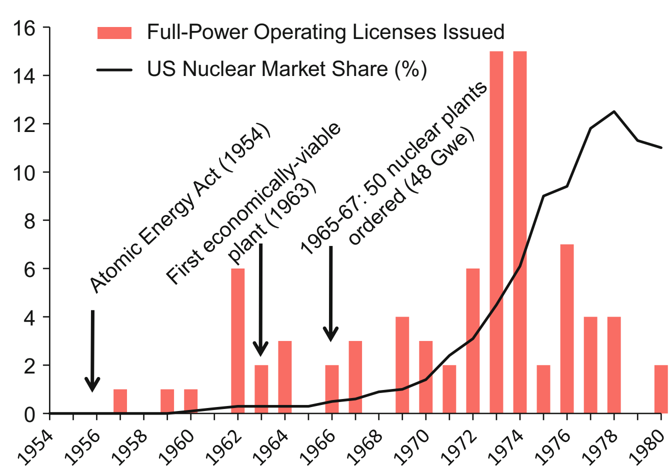

Fig. 3. Milestones in the development of the US nuclear power industry. Market share is based on actual power generation. The last construction permits for nuclear plants in the US were granted in 1979 for two plants. It was not until 2007 that three 'early site permit' (ESP) were given. An ESP status declares a site to be suitable from safety, environmental, and related grounds for new nuclear power plants. At this writing, there are 18 proposed plants at various stages of regulatory approval and perhaps 4–8 new plants will be built over the next decade or two. *Data source*: EIA (2007b) and EIA (2009).

customers, so price of LNG was not a big concern (Mehden and Steven, 2006). Thus, even as early as the 1970s in the LNG business when there was not much experience with liquefaction technologies or transportation of LNG, the willingness of Japan to almost unilaterally absorb the risks proved critical to the expansion of LNG.

7. Technology diffusion through business-risk reduction

Technologies continue to operate only in niche markets until the business risk of expanding to gain market share reduces significantly. There are three principal risks to the business model: excessive cost of the technology, insufficient revenue, and liability for unanticipated negative consequences. Risk can be mitigated internally by the party implementing the technology—usually through efforts to reduce cost through innovations in technology or processes, or economies of scale—or by seeking external arrangements that minimize exposure to business-model uncertainties. External risk allocation, i.e., shifting risk from firms to external actors—often governments—can be particularly important for highly capital-intensive technologies. Government guarantees often play a central role. Actions for external risk allocation can address all three sources of business-model risk: cost, for example through investment grants or guarantees during the permitting process to prevent cost escalation; revenue, by guaranteeing a market for the technology (as with a portfolio or performance standard) or by providing for full cost recovery; and liability, by transferring liability risk to another entity (usually government). Partnerships for risk allocation can also play an important role in limiting downside risk overall. Such partnerships can assume a myriad of forms, but a common example is exclusive partnership for co-development of a value chain. This is routinely followed, for example, in the oil & gas industry for the development of complex deepwater fields and for complex LNG projects.

7.1. SO_2 scrubbers

The 1971 New Source Performance Standards (NSPS) promoted wide experimentation with different technology options for SO_2-emissions control. But, although government support for R&D in SO_2-control technologies and early regulations limiting SO_2 emissions stimulated technology development and initial scrubber markets, the event that dramatically decreased risk and thus paved the way for large-scale adoption was government action to guarantee a market for FGD. This came through the revision in 1979 of the 1971 NSPS regulations to effectively create a technology mandate for FGD. The regulators seized on a technology (FGD) that seemed viable, and adapted rules to directly incentivize investments in it. Switching from a performance-based standard used in the 1971 NSPS (see Section 6.1) to a technology-based standard, the 1979 NSPS required all new coal-fired power plants to remove between 70% and 90% of sulphur depending on the sulphur content of coal used. Although a number of SO_2-control technologies besides FGD systems were in active development and commercial use before, the stringency of the 1979 NSPS was a verdict in favor of FGD systems. It created an assured and large market share for this technology—a strong "demand pull" (Rubin et al., 2004).

7.2. US nuclear power industry

The growth of nuclear power in the United States (and in other OECD countries) was stimulated by a number of external risk allocation deals backed by government. The US Atomic Energy Act of 1954 had at its heart the promotion of private investment in the nuclear power industry. Even with such a strong policy push, there were several factors that prevented significant private investment in the industry through the 1950s and early 1960s (Fig. 3). First, there was little experience with the generation technology and its operation at commercial scale, so costs remained highly uncertain. By contrast, the main rival for baseload power—coal and oil-fired boilers—were well-understood technologies with known performance and pricing. Second, potentially large liability associated with accidents or nuclear-waste disposal were significant concerns. Magnitude of risk in both these cases was perceived to be high by private investors (Lönnroth and Walker, 1979), and they wanted clear assurances of government's help before forging ahead with investments.

The government moved swiftly to respond to these demands. To limit liability from reactor accidents, the Price-Anderson Act was enacted in 1957, which restricted private liability to \$60 million (Berkovitz, 1989); the government assured another \$500 million to cover additional claims. Government's plutonium repurchasing program from utilities effectively made waste disposal a government responsibility (Campbell, 1988). Further, the Atomic Energy Commission (AEC) essentially underwrote the cost of the entire first generation of US civil nuclear reactors (Campbell, 1988).

The situation was similar in other OECD countries, like the UK, Germany, France, and Japan, especially until the late 1970s. France and Germany, for example, even assisted in providing low-interest loans to the industry, through either direct or indirect control of money flow (Campbell, 1988; Hecht, 1998). It is clear, then, that the development of nuclear power was greatly aided by extensive external risk-allocation deals. That all these deals could be successfully put together also reflects the fact that the proponents of nuclear power were very well organized.

7.3. LNG

For LNG, both external and internal risk reduction played a part in different cases. In the Pacific basin, where Japan was by far the predominant buyer of LNG through the 1990s, deals exclusively focused on external arrangements. Such deals, as discussed above, demonstrated LNG as a viable option for moving large quantities of gas across continents. But globally LNG failed to dent natural gas markets till mid-1990s, and its success remained restricted to projects directly supported by Japan.

With the dominance of piped gas in Atlantic basin countries (US and Western Europe), the situation there was quite different, and both internal and external risk reduction played a role in diffusing widespread use of LNG. LNG faced fierce competition from cheap piped gas, which rendered LNG economically unviable in most settings. Particularly instructive and relevant to our discussion is the Atlantic LNG project, for the import of LNG to the northeastern United States and Spain from Trinidad & Tobago. Cabot LNG, a small player in the LNG business and the initiator of the Atlantic LNG project, was facing a struggle for survival in the early 1990s in the heart of its main market, the northeastern US. Competitors were planning increased piped supplies to this region from Canada. Cabot LNG's only option was LNG from Trinidad & Tobago, but cost as it stood was not competitive: while the average LNG price into Japan was \$3.52/mmbtu (\$3.34/million kJ) in 1993, the US Henry Hub price (the benchmark for gas in the US) was \$2.12/mmbtu (\$2.01/million kJ). It was clear that for economic viability, LNG imports into the US would have to be robust against domestic gas prices of \$2/mmbtu (\$1.90/million kJ) (Shepherd and Ball, 2004).

Hard pressed for survival, Cabot LNG utilized both of the risk-reduction options, external as well as internal. It formed a joint venture company Atlantic LNG with Amoco, British Gas (BG) and Trinidad & Tobago National Gas Company in 1995; Spanish utility Repsol later joined the venture. These partnerships, a hallmark of an external risk reduction strategy, not only allowed the project to distribute risk and rewards among the participants by offering multiple options for the destination of the supply, but also brought in wide-ranging technical and commercial expertise from the partners to bear upon the cost problem.

Cost being the prime issue for the viability of the Atlantic LNG project, the partners responded through path-breaking commercial and process innovations as a method of internal risk reduction. Atlantic LNG changed the then-standard practice of providing the same firm with both Front-End Engineering and Design (FEED), and Engineering, Procurement, and Construction (EPC) contracts. Instead, they ushered in the "dual FEED" strategy—the practice of having two firms do FEED in parallel. This strategy was successful in generating significant competition among contractors and lowering costs. Atlantic LNG also came down heavily on superfluous system design elements, like excessively generous safety and capacity factors, which were a legacy of the Japanese dominance in the LNG markets (in the next section we discuss in more detail the cost implications of Japanese dominance). As a result of these innovations, within three years of redesign, but still using only off-the-shelf technology, the developers were able to lower the cost of a 3 million tonnes per annum (mtpa) LNG plant to $750 million, compared to the $1 billion initial estimates for a 2.3–2.5 mtpa plant (Shepherd and Ball, 2004). At the same time, swift movement allowed LNG to beat new pipelines to the lucrative northeastern-US markets where delivered gas prices were relatively high due to pipeline bottlenecks.

8. Cost experience curves

Cost reduction increases the competitiveness of a technology relative to incumbent technologies, and enables the technology's wider diffusion in the relevant market space. (In addition to direct reductions in technology cost, this could take the form of long-term regulatory regimes that advantage the technology relative to competitors, for example by pricing in externalities.) A number of good studies discuss "experience curves" and "learning curves" to explain cost reduction over time for technologies, including energy technologies (Isoard and Soria, 2001; Lieberman, 1984; Neuhoff, 2008). The theory is based on the empirical evidence for a large number of technologies that costs generally decrease with increasing installed capacity. In the literature this concept is usually captured through the term 'learning rate'. Learning rate is defined as the percentage decrease in cost of the technology for each doubling in the installed capacity (positive values for learning rates indicate decreasing costs). The direction of causality is often debated (Alberts, 1989), but the (mostly) negative correlation between cost and installed capacity is well established: for energy-technologies, although learning rates vary from −4% to 34%, most values lie between 4% and 30%, with a median of 16% (Grübler et al., 1999; McDonald and Schrattenholzer, 2001; Rubin et al., 2004). Nobel laureate Kenneth J. Arrow was the first to propose a theory that endogenizes learning ("changes in knowledge") as the underlying cause of cost reductions ("shifts in production functions") (Arrow, 1962). In this section we discuss the learning curve for cost reduction as the analogous technologies considered in this paper diffused more widely.

8.1. SO_2 scrubbers

The learning effect for FGD technology is shown in Fig. 4, which plots capital costs of FGD systems ($/kWe) as a function of installed capacity (GWe). The US government had provided direct funding and R&D support to the SO_2-scrubber industry in general since the 1950s; the support grew stronger during the 1960s and even more so during the 1970s, when public R&D expenditure for SO_2 control peaked at nearly $90 million in 1975 (Taylor et al., 2005). But only after the 1979 NSPS both capital and operating and maintenance (O&M) costs of FGD systems declined most significantly (). The cost improvements are attributable to technological innovation (e.g., new materials, better control of process chemistry) and process innovation (e.g., reductions in reagent and process energy use) (Rubin et al., 2004). That FGD is modular to existing plant equipment makes it easier to realize such innovations, which in turn reduces costs. As discussed earlier, the NSPS of 1979 effectively required all new coal-fired power plants to use FGD systems (wet FGD for high-sulphur coal; dry FGD for low-sulphur coal). Thus, although successful cost reductions for FGD systems following the 1979 NSPS were built upon sustained public R&D in the prior two decades, the learning effect with FGD technology really accelerated only after regulation provided a clear direction—in this case by picking a technology winner. While it was the private sector that did nearly all of the investment in this area, the private sector would not have undertaken this mission without a stringent technology forcing requirement that both mandated introduction of the technology and also (through rate of return regulation) dramatically reduced the financial risks associated with the investment. The rate of introduction of FGD technology under this regulatory regime was probably much faster than in a performance-based and market-oriented system.

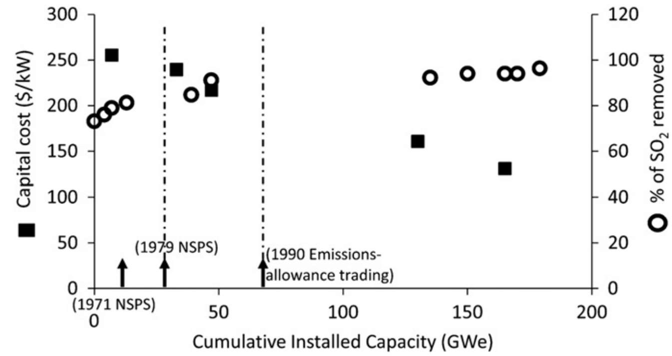

Fig. 4. Capital cost (left axis) and performance (right axis) of US FGD systems as function of the cumulative installed capacity. *Data source*: Taylor et al., 2005.

8.2. US nuclear power industry

The experiences of nuclear power in the US and the LNG industry tell a different story about learning curves—in both these cases, costs did not necessarily come down as installed capacity increased. In the US nuclear power industry this anomalous cost behavior was caused by an unsustainably high rate of growth; unclear and changing regulatory requirements further complicated the situation. It could be argued that the risk-allocation deals provided in the hurry to support and incentivize the industry ended up taking too much risk away from investors, leading to "irrational deployment" that has ultimately hurt the industry.

Fig. 5 shows the average estimated capital cost at different stages of construction of nuclear power plants in the US that started construction between 1967 and 1977 (total 75 plants) (Gielecki and Hewlett, 1994). Clearly, the costs were significantly underestimated. In fact, even the estimates made when the plants were 90% complete were 13% lower than the final realized costs (Gielecki and Hewlett, 1994). A number of factors caused the costs

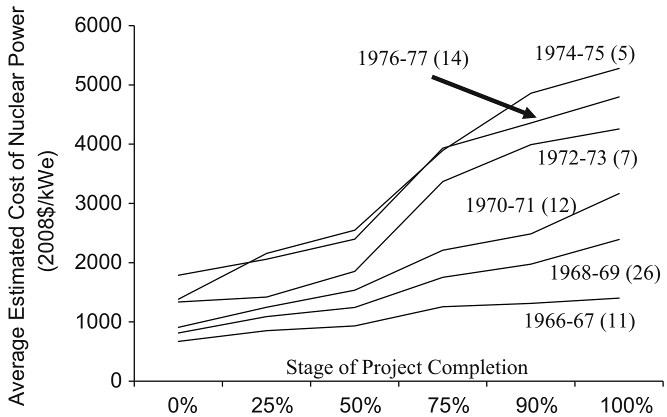

Fig. 5. Average estimated capital cost of US nuclear plants at different stages of project completion. The number in parentheses is the number of projects that began construction in the indicated years. Cost estimate at 0% completion is the initial estimate, at 50% completion is the estimate at mid-stage, and at 100% completion is the final realized cost. *Data source*: Gielecki and Hewlett (1994).

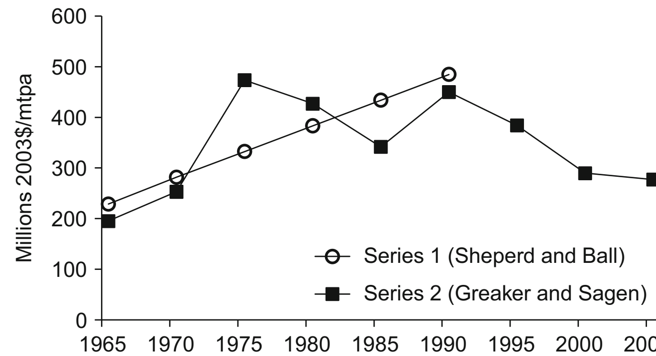

Fig. 6. Historical unit cost of natural gas liquefaction plants (millions of 2003 USD/mtpa). mtpa: million tonnes per annum. *Data source*: Series 1—Shepherd and Ball (2004); Series 2— Greaker and Sagen (2008).

of nuclear plants in the US to explode in the 1970s, but two factors were most damaging: a very-rapid growth rate and changing regulatory requirements (Campbell, 1988; Gielecki and Hewlett, 1994; MacKerron, 1992). The 515-MWe nuclear reactor ordered in 1963 by the Jersey Central Power and Light Company was the first commercially viable plant (Fig. 3). GE supplied the reactor at a considerable subsidy; it considered the deal a "loss leader" that would spur future demand for its reactors—a market-penetration pricing strategy (Campbell, 1988; Henderson, 2000). Indeed, competitive pricing of reactors coupled with very optimistic projections of capital and levelized cost of electricity from nuclear power plants created a flurry of demand for nuclear plants. Between 1966 and 1970 a total of 76.2 GWe nuclear-power capacity was ordered, which represented over a third of the total generating capacity ordered during this period (Campbell, 1988). The competition was so fierce that reactor manufacturers were constantly changing design to offer customers ever-increasing reactor capacities. The logic was that economies of scale would bring costs down. The reality, though, was quite different. Constantly changing design precluded the standardization that would have led to economies of scale (Campbell, 1988; Gielecki and Hewlett, 1994; MacKerron, 1992). An excessive rate of deployment of nuclear plants put tremendous strain on the EPC contractors, who until then had little experience in the business. But more importantly, rapid parallel deployment robbed the industry of the opportunity to apply learning from a tranche of projects to the next series of projects.

Regulatory agencies further complicated the issue. By the late 1960s safety and waste disposal from nuclear plants had captured the public attention and become an important part of the ongoing environmental movement (Carson, 1962; Nader and Abbotts, 1979). Partly in response to the environmental movement, regulators asked project developers to augment safety features at plant sites; in many cases this happened after construction had begun. All this necessitated additional design changes and caused significant delays, both of which further escalated the cost of building nuclear plants (Campbell, 1988; Gielecki and Hewlett, 1994; MacKerron, 1992).

8.3. LNG

The cost of natural gas liquefaction systems (to the project developers) did not start declining until after the mid-1990s, nearly 35 years after the first transoceanic shipment of LNG in 1959. Fig. 6 shows the historical unit cost of liquefaction plants. In this case, the lack of cost reduction was attributable to a peculiar market structure involving a dominant buyer (Japan) and little competition on the (technology) supply side.

The skewed dynamic between the supply and demand for the LNG technology from early 1960s to mid-1990s affected its cost in several ways. First, there was almost no competition in technology, as Air Products' APCI process dominated the liquefaction technology market. Second, the construction market was also marked by its lack of competition. Only four major contractors—Kellogg, JGC, Bechtel, and Chiyoda—built LNG plants, often working together in JVs (Shepherd and Ball, 2004). Third, as far as demand was concerned, Japan was the dominant buyer of LNG, and it was willing to pay premium prices. In fact, Japan's appetite for LNG was so strong even in the 1960s that it went scouting all over the world for possible suppliers, with notable success in Alaska, Indonesia, and Abu Dhabi. An oligopoly in the supply of liquefaction technology combined with strong LNG demand backed by Japan vested significant market power with the technology and engineering firms, providing them with opportunities for markups. Fourth, Japan was inordinately concerned with the safety and security of LNG supply. This resulted in generous capacity and safety factors for the liquefaction plants, which further added to the costs. Fifth, a final factor that likely contributed to the lack of cost reduction was the structure of global liquefaction capacity. Only 20 liquefaction terminals with a total capacity of about 50 mtpa were built worldwide between 1960 and 1995 (Greaker and Sagen, 2008). The temporal and geographical separation of construction of the liquefaction plants may have hindered learning-by-doing.

Japan's LNG experience suggests that there may in some cases be a tradeoff between risk-allocation approaches and the subsequent degree of success in reducing costs. On the one hand, strong government backing is one of the most effective means of risk reduction to support development of a risky but potentially important technology. On the other hand, such backing can undercut the efficiency of markets and thus potentially freeze costs at a higher level than they could potentially achieve.

9. Lessons for development of CCS

9.1. Technology innovation and demonstration

One important niche market for CCS already exists, that for CO_2-EOR. This is an example of a risky and capital-intensive technology for which the niche market was successfully established by private players with strong support from the government (financial incentives in the form of tax breaks). In the 1970s the US government was actively promoting domestic EOR activities to reduce oil imports; high oil prices and government incentives provided a good business opportunity for the industry—and the CO_2-EOR industry was born.

CO_2 was first injected for EOR in Scurry County, Texas in 1972 (DOE, 2009). At present, nearly 100 CO_2-EOR projects in the US enable the production of about 237,000 barrels per day (bpd) of oil, which is roughly 5% of US crude oil production; the annual demand for CO_2 from these EOR operations stands at more than 40 million tonnes (Apt et al., 2007; NRDC, 2008; Kuuskra, 2008). The CO_2-EOR industry, mostly in the Permian Basin in West Texas and eastern New Mexico, has provided over three decades of experience with CO_2 transportation and injection. It has also helped establish the viability of carbon storage in depleted oil and gas fields. (Unfortunately, it has not provided much insight into issues of storage in more widespread types of geological structures like deep saline aquifers.)

Looking ahead, the niche for carbon storage from CO_2 enhanced hydrocarbons recovery, including CO_2-EOR, is poised to grow. Fig. 7 displays the potential volume of CO_2 stored through 2025 by announced carbon-storage projects. The projects were broadly grouped by the probability of their completion: currently operating (100% likelihood), possible (estimated 50–90% likelihood), and speculative (estimated 0–50% likelihood) (Rai et al., 2008). The projects are color coded according to the destination of the CO_2: enhanced oil recovery (EOR), enhanced coal-bed methane (ECBM), and Natural Gas (NG) operations (Black); saline aquifers and depleted oil & gas fields (White); unknown (Gray). It is clear that most of the "operating" and "possible" projects are related to EOR, ECBM, or NG operations. This is not surprising given that as yet there is no direct economic incentive for CCS operations in most cases; besides government grants, at present the only other way to make CCS projects economically viable is to use the CO_2 for producing more hydrocarbons to take advantage of relatively high oil and gas prices (compared with historical levels).

More electric-power-oriented CCS projects appear in the pipeline post-2015 (5 Mt CO_2/yr in 2010; 65 Mt CO_2/yr in 2015; and 90 Mt CO_2/yr in 2025). Wider application of CCS to the electric-power industry is essential if CCS is to be a central player in efforts to slash CO_2 emissions (EPRI, 2007; WRI, 2008). A niche market for commercial-scale carbon-capture technologies—presently by far the most expensive step in the CCS value chain—has been missing so far. The situation is changing as several governments plan to ramp financial support for CCS demonstration projects. Governments' interest in CCS is generally rooted either in concerns about global warming or in the desire to continue to use coal or unconventional oil reserves even in a carbon-constrained world. Concerned governments, notably the US, European Union (EU), Australia, and Canada (Alberta and British Columbia), are gearing up to provide multi-billion dollar support for CCS-related R&D projects (AG, 2008; Boucher, 2008; EPR, 2008). Based on development of the industries discussed earlier in the paper, the creation of a niche market for large CCS projects based on special government support appears to be the normal course of development.

Businesses recognize the strategic value of CCS as well. But given the uncertainties around CO_2 regulation and the high capital intensity of CCS (even on a semi-commercial scale), they have been unwilling to take on much of the risk. Markets are most likely to spring up in situations where strong government interest in CCS coincides with strong business interest, for example in industrial gasification applications or in chemicals industries. Here again, those businesses for which CCS is strategically highly important (or who see the ability to leverage an existing competence to grow a new business) will be more likely to share the early adoption risks. Such businesses include coal producers and suppliers of CCS technology. If future regulations constrain carbon emissions more severely than current ones, the success of CCS will be important to maintaining a strong market for coal. The sheer potential scale of CCS applications also make CCS attractive for providers of technology—combustion technology (GE, ConocoPhillips, Siemens), carbon-capture technology (Alstom, Praxair, Fluor, and others), and sequestration technology (Oil majors, Schlumberger, and others).

9.2. Technology diffusion through business-risk reduction

For CCS, business risks are very high at present. Particularly limiting the growth of CCS now are its high capital requirements coupled with uncertain revenue, a situation very similar to the early days of both nuclear power and LNG. The previous discussion on the risk-reduction strategies adopted by the nuclear power and LNG industries suggests that over the next decade or so growth of the CCS industry will be particularly dependent on the ability of its proponents to allocate risk externally. CCS proponents are adopting this strategy. At last count about \$17–20 billion is available through government schemes or voluntary

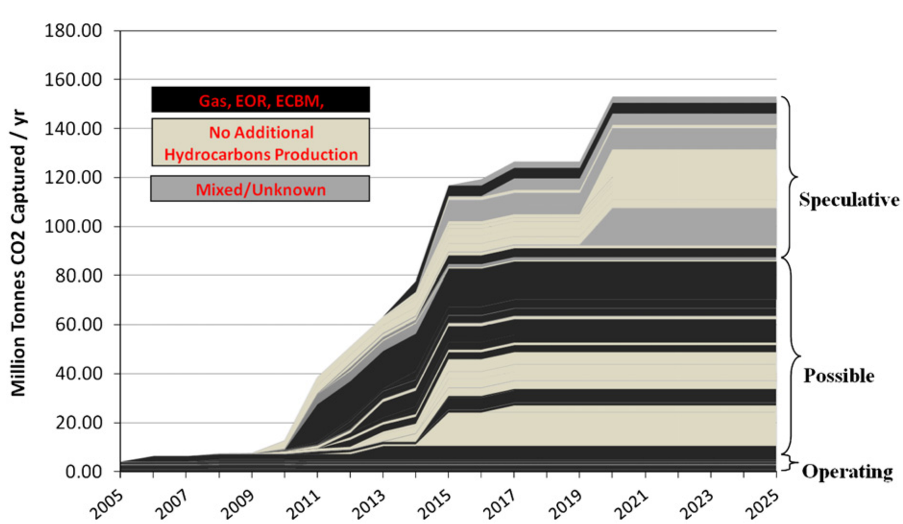

Fig. 7. Carbon storage projects worldwide. Color scheme distinguishes between the final destinations of CO_2. *Source*: Rai et al. (2008).

industry levies to promote CCS globally (GCCSI, 2009). This also suggests that CCS proponents are well organized, as was the case with the proponents of nuclear power in the 1960s (see Section 7.2). Another option to allocate risk externally would be to include the CCS industry in a carbon trading scheme to provide guaranteed revenue from selling CO_2 permits generated through emissions reductions that the CCS projects achieve. However, as a source of revenue for CCS projects, carbon prices—even if hefty—will not be sufficient to drive investment in the technology. What is needed is direct support and protection for financial performance. These are such big and financially risky projects that investors will not pursue them based on the median price of carbon; they will look at worst case scenarios (lower than expected carbon prices and worse than expected financial performance), and by those metrics CCS is still a long shot. In Europe CO_2 prices are highest in the world, yet not enough to incentivize much investment in this area without direct support. Put more bluntly, to achieve substantial experience with CCS operations—considered necessary by many (EPRI, 2007; IPCC, 2006; WRI, 2008)—somebody has to underwrite the massive financial risks associated with today's CCS industry—for nuclear power and LNG that "somebody" was government.

9.3. Cost experience curve

Our analysis suggests that the simple assumption that CCS costs will fall over time could be upended by future surprises. The expected cost reduction due to technology learning may be particularly at risk if CCS is deployed too aggressively, if regulations are unstable, or if the market structure for the technology is not competitive (for example because it awards excessive market power to the suppliers of the technology).

On the more optimistic side, some technological similarities between FGD technologies and the CO_2-capture technologies presently available (for example, absorption systems based on chemical or physical solvents) could indicate that learning effects should be expected for CO_2-capture technologies as have been observed with FGD systems (). This is good news, as CO_2 capture is the most expensive step in the CCS value chain. But, as evidenced by the history of wet FGD technology, most of the learning (in terms of cost reductions) happens *after* clarity is established on the technology's likely market share, at which point competitors drive costs down aggressively to vie for a piece of the market. For CCS, until such point as some form of mandate—say, a feed-in tariff, or portfolio standards—establishes a guaranteed market for it, CCS technology improvement and learning will likely continue under the aegis of public funding, or at best as public–private partnerships.

The experience with the cost of nuclear power in the US imparts two important lessons for the CCS industry. First, too fast a growth rate of a technology can actually cause its cost to increase as installed capacity increases. This may happen because excessively fast roll out precludes the ability to incorporate learning in new units (Campbell, 1988; Neuhoff, 2008). Capital-intensive technologies, like CCS, are particularly prone to this type of negative experience curve. Second, uncertain and shifting regulations can further counteract any benefits from learning. This is especially important in regulatory contexts where consumers and the general public have significant access to the regulatory process—as is the case in the US. For CCS there are unresolved issues about long-term liabilities associated with the behavior of the injected CO_2. As such, consumers and regulators will likely be quite vigilant regarding development of CCS and thus demand close monitoring for decades (EPA, 2008; Figueiredo and Fadil, 2008; Klass and Wilson, 2008). For this reason, the cost of CCS projects may remain exposed for a long period to regulatory shocks.

The experience with natural gas liquefaction systems highlights the well-understood economic harms to consumers that can result from limited competition (oligopoly) or no competition (monopoly) on the supply side. In addition, consumers who demand extremely robust systems—reminiscent of Japan's preoccupation with safety and security of LNG supply—put upward pressure on costs. With almost everyone showing marked concern for the safety of CCS projects, this premium on developing "bulletproof" systems could come into play for costs of CCS projects as well.

10. Conclusion

In this paper we draw lessons for the CCS industry from the history of other energy technologies that, as with CCS today, were risky and expensive early in their commercial development. Specifically, we analyze the development of the US nuclear-power industry, the US SO_2-scrubber industry, and the global LNG industry. Through analyzing the development these analogous industries we arrive at three principal observations relevant for the CCS industry.

First, for all of these analogous technologies government played a decisive role in their development. Notably, analogous technologies usually benefitted from substantial government support—often in the form of direct payments—for R&D and then early deployment in attractive niche markets. Today, we observe the early stages of similar government support for CCS. But uncertainties about that support are leading private industry to advance CCS, so far, mainly in niche markets such as EOR or gas processing that align with industry interests. More slowly, direct government support is beginning to attract investment in trial projects and full scale demonstrations in projects to store CO_2 in saline aquifers or depleted oil and gas fields. Economically, the most important tests arise with carbon capture, which is much more costly and financially risky than carbon storage. Here, too, government support is emerging slowly.

Second, the successful diffusion of these analogous technologies beyond the early demonstration and niche projects hinged on technical performance and the credibility of incentives for private industry to invest in commercial-scale projects. In theory, such incentives could have been supplied by non-governmental institutions, such as large firms or industry associations that favored the technologies. In practice, the three analogs point strongly to a governmental role because, in contrast with non-governmental institutions, governments are much more able to direct investment decisions through policy decisions. The pivotal factor in these analogous cases is the credibility of government policy since in all these cases the investments were long-lived and financially risky. Credible promises from government are likely to be critical also for CCS as it moves into the diffusion phase. A few governments are crafting diffusion policies already. For instance, the Waxman-Markey bill in the US proposes strong economic incentives (up to \$90/tonne CO_2) for up to 72 GWe of power capacity (over 100 plants) equipped with CCS. Such policies are necessary. But, of course, the extraordinary ability of government to direct commercial investment must be tempered by the perennial troubles with government policy for pre-commercial technologies, which is the difficulty in ensuring that government managers make wise choices and back the right technologies. Often, government choices are based on the learning curve theory—that experience with technologies inevitably reduces costs.

Third, these analogous cases suggest that the learning curve theory often does not hold and it is difficult to know *ex ante* when learning will be positive or even negative. Indeed, we observe negative learning for some of the history of nuclear power in the US (1960–1980) and global LNG (1960–1995). Costs *increased* as cumulative installed capacity increased. And we observe positive learning for other periods, such as LNG since 1995. Real learning depends not just on technical potential but also the institutional environment and the incentives to cut costs and boost performance. As CCS commercialization proceeds, policymakers must remain mindful that cost reduction is not automatic—it can be derailed especially by non-competitive markets, unanticipated shifts in regulation, and unexpected technological challenges. History suggests that government-backed assurances are essential to creating the market for capital-intensive technologies; yet those very assurances can also create the context that makes it difficult for investors to feel the pressure of competition that, over successive generations of technology, leads to learning and lower costs. A sheer emphasis, as we see today, on very aggressive deployment of CCS is likely to repeat the negative experience on cost curves. A more beneficial strategy for CCS deployment over the long term is to focus on designing CCS RD&D programs that emphasize adequate learning between generations of CCS technologies and that facilitate standardization of important design parameters, while fostering competition among equipment suppliers.

Although not a focus of this paper, power market structure might also have implications for CCS deployment. Today there are some countries with deregulated power markets and a large share for private companies, although that mode of organization is actually still in the minority because it has proved very difficult in practice to implement effective power sector reforms (Victor and Heller, 2007). To the extent that the power industry moves fully private the need for active and clear policy to encourage risky long-term investments in new technology, such as CCS, probably grows. So far, very few countries have done that successfully; indeed, the experience with power sector reform generally is that long-term goals are eclipsed by the near-term practical difficulties in finding viable business models that work in a deregulated power market.

We are also mindful that our history here—drawn on the experience of three technologies that have been successful in obtaining a substantial market share—is a biased one. By looking at successes we are perhaps overly prone to derive lessons for success when, in fact, most visions for substantial technological change actually fail to get traction.

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