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Explaining experience curves for LNG liquefaction costs: Competition matter more than learning

Abstract:
In this paper we seek to identify different driving forces behind the fall in LNG liquefaction unit costs. Our focus is on organizational learning including process specific R&D, but we also seek to account for autonomous technological change, scale effects and the effects of upstream competition among liquefaction technology suppliers. To our surprise we find that upstream competition is by far the most important factor. This may have implications for the future development in costs as the effect of increased upstream competition is temporary and likely to weaken a lot sooner than effects from learning and technological change. On the other hand, the increased competition could also spur more innovation, and induce a new drop in future unit costs.

Keywords: Learning curves, Mark-up pricing, LNG costs

JEL classification: O31, Q41, Q55

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1 Introduction

In this article we study the technological, institutional and organizational factors that have influenced the cost of liquefying natural gas (LNG) after the first LNG plant came on stream in 1964. A large part of discovered gasfields are situated too far away from the major gas markets to make direct pipeline transportation viable (see IEA (2001)). Such gas fields are often coined *stranded gas fields*, and it is the desire to capitalize these gas reserves which has spurred the development of the LNG industry.

Today, LNG is regarded as one of the fastest growing sub-sectors of the energy industry. According to many sources, e.g. EIA (2003), prospects for continued growth are very good; there is increasing demand for combined cycle gas turbine electricity generation (CCGT), major energy markets are in the process of being deregulated making it easier to sell LNG, and costs in the LNG supply chain have decreased radically the last decade. In addition, some regions, as the U.S., seem to have entered into a situation with a chronic natural gas supply shortage. For some of these regions LNG may be the only viable solution.

To our knowledge, there exists no recent study in the economics literature of LNG supply chain costs. In this paper, we therefore look at the following two research questions: What are the factors driving the fall in liquefaction unit costs? To what extent is the cost of liquefaction likely to fall further? In order to answer these questions we have used historical data to estimate experience curves for the construction of LNG liquefaction plants, also taking into account other relevant factors than pure experience. We base our estimation on a unique data set with price and scale information on nearly all LNG liquefaction plants and the number of LNG liquefaction technology suppliers at each point in time.

Experience curves may be powerful tools when it comes to explaining past and indicating future cost gains for relatively new technologies. In its basic form, an experience curve explores the relationship between accumulated production at time t and average cost of production at time t. It has been shown in numerous studies that a significant, negative trend can be found between the cost of a new technology and accumulated supply of this technology, take for instance the CCGT electricity generation technology (IEA (2000)).

There are at least four, more fundamental, mechanisms at work behind an experience curve, see IEA (2000). First, as personnel engaged in the planning and production of the new product gain experience with the new technology, say an LNG liquefaction plant, they are likely to become more efficient and better organized to perform the tasks at hand. This improves the productivity of labour, and unit costs are reduced. The process is often coined "learning by doing", and was first formally described in the seminal paper by Arrow (1962).

Second, experience may also induce research and development (R&D). This may lead to further improvements in technology - so called process innovations- which also reduce unit costs. Some studies have tried to separate the effects of organizational learning and induced R&D by keeping track of targeted public funding to R&D projects, see for example Ibenholt (2002) and Jespersen (2002). However, technological progress may also be independent of experience with the product under study, e.g. gas turbines have become more effective, which have implied savings in the overall project cost of an LNG plant. If both an independent technological progress and accumulated production increases over time, one may exaggerate the effect of actual production experience, if this independent technological change is not accounted for.

Third, it is often the case that the market for a new technology is poorly developed, hence, potential scale advantages in the production or process technology cannot be explored. As time goes by, the size of the market may increase, and so does the scale of each production unit. Thus we will observe that costs decrease with accumulated production, but then it would be wrong to interpret this as technical progress in a strict sense. This is pointed out in Hall and Howell (1985). However, increased scale of production can also become possible due to technological progress, e.g. due to better materials technology, it has become possible to build larger cooling towers.

Fourth, when the market size picks up, more firms enter and start to supply the new technology, and prices fall due to increased competition. In this case it would clearly be wrong to interpret the fall in producer prices as technical progress or organizational learning. In most empirical applications average cost is not observable, and the price of the product in question is used instead. As long as the price is used as a proxy for unit costs, we may also have an effect on the observed unit price through increased competition.

While learning and technological progress can continue to work together for a long time, the limits of the scale effect and the competition effect with respect to cost savings are likely reached much sooner. Our aim is therefore to separate the influence on costs from the different effects in our experience curve estimation. We confine our study to the effects on capital cost, that is, the cost of building a natural gas liquefaction factory. For an LNG plant, capital costs generally amount to more than 95% of the total annualized expenditure, of which roughly 75% is total direct costs (see IEA (2001) and DiNapoli (1986)).

Moreover, we concentrate on the liquefaction part of the LNG supply chain. According to for example Petroleum Economist (2001) and Weems (2000), the capital cost of LNG liquefaction, make up about 40-50% of total LNG-chain capital costs. In a forthcoming discussion paper we study the two other major cost components; transport costs and regassification costs, see Greaker and Sagen (2005).

Our study is inspired by Joskow and Rose (1985), who investigate the construction costs of coal-burning generation units in the US. They find an organizational learning effect which can be separated from the scale effect. Although the study of Joskow and Rose (1985) have many similarities with our study, the two studies differ in an important aspect. While we only have data on the price paid by the buyer of an LNG liquefaction facility, they have access to cost data. Thus, they do not have to take into account that the mark-up over marginal cost may have varied between the observations.

Our paper attempts to include mark-up pricing in the experience curve model estimation. This is also done by Lieberman (1984) in his study of chemical industry products. Lieberman (1984) looks at different levels of market concentration using the Herfindahl index to separate the data. The study reveals that the negative effect on the price from new market entry was significantly higher in an initially high market concentration situation compared with a low market concentration situation.

We are aware that there exist both databases of LNG costs, and detailed cost models of LNG plants, see for example DiNapoli and Yost (2003). However, both the databases and the models are the proprietary of consulting firms, and not available to the public. Hence, as far as we know, this paper presents the first generally available econometric analysis of LNG plant capital cost developments.

The paper is organized as follows: The next section discusses some theoretical features of market competition when costs depend on accumulated output. The third and fourth section includes a short introduction to LNG liquefaction technology and factors driving the capital cost of liquefaction facilities. Section five explains our data sources, and briefly discusses an important anomaly in the dataset. Section six and seven sets out our estimation model, and section eight presents our results. In section nine we conclude.

2 Experience curves

In its basic form an experience curve describes the relationship between unit costs/unit price and accumulated production of some commodity, see Boston Consulting Group (1972). It is assumed that experience with production of the commodity can lead to both organizational learning and technological advances. Most recent studies of experience curves, see e.g. IEA (2000), have used a variant of the following equation in order to describe the experience process:

$$c_i = a_0 Q(t)^{-a_1}, \tag{1}$$

where c_i is the unit cost, $Q(t)$ is accumulated production at time t and a_0 and a_1 are positive parameters. The parameter a_1 expresses the speed of the experience process, that is, the higher the a_1, the faster will costs per. unit decrease with accumulated output.

Experience can be either industry wide of firm specific. In the latter case $Q(t)$ denotes the accumulated production of a single firm. If the firm is forward looking, it would take future gains from experience into consideration when setting the current price. This is analyzed in a seminal paper by Spence (1981),both for a monopoly and for an oligopoly with sequential entry. According to Spence the monopoly will not equate marginal income with current marginal cost. Instead the relevant marginal cost is the cost of the last unit i.e. at the end of the time horizon. Hence, the monopoly will operate with a negative mark-up and a negative profit the first years.

Introducing more firms do not change this result as long as experience is firm specific. The first firm to enter the market will enjoy lower costs than later entrants at all periods, and hence, be able to make positive profits in the future outweighing the initial negative profits. However, matters change if there are extensive spill-overs between firms, that is, experience is industry wide. Later entrants can then operate with nearly the same costs as the first firm making it harder for the first firm to cover initial losses. Thus, with industry wide experience, firms are not likely to set prices below marginal costs in the start-up of a new market.

Of course, if only price data is available, forward looking firms and limited spill-overs make estimating experience effects from accumulated production very difficult. In the case of a monopoly you could observe a constant price even though the unobserved unit cost was monotonically falling (Spence (1981)).

In our analysis we assume that liquefaction technology firms are not forward looking, but that they base their pricing decisions on current unit costs. Through out the history of LNG the development of the market for LNG liquefaction plants has been sluggish and uncertain - especially before 1999. Thus, it must have been difficult for the liquefaction technology firms to form expectations about future demand, and future learning possibilities. Years have passed without any new liquefaction facilities being built, hence, historical pricing of liquefaction technology, with point of departure in an uncertain marginal cost sometime in the future, seems unlikely.

3 LNG liquefaction technology

The first LNG liquefaction unit came into operation in 1964 at Arzew, Algeria. The liquefaction process takes natural gas and cools it via compression to -161^0 C, shrinking it to $1/600th$ of its original volume and making transportation by ship economical. Natural gas consists mostly of methane CH_4, but also includes other substances like sulphur, CO_2, C_3H_8 (prophane) etc. These substances must be removed from the natural gas before cooling it down to -161^0 C. If not, they become solid, and may interrupt the cooling process. A LNG liquefaction unit therefore also produces other chemicals like solid sulphur and LPG (liquid prophane/buthane gas).[1]

A typical LNG liquefaction plant consists of one or more process trains. A process train can be viewed as a standalone liquefaction unit, that is, one process train can be shut down without affecting operations at adjacent trains. The cooling process can be achieved by one of several proprietary methods. A majority of the liquefaction plants use the method developed by Air Products and Chemical Inc. (APCI), which is referred to as a mixed refrigerants with

[1] Se for instance Institute for law, energy and enterprise, "Introduction to LNG" (2003).

propane precooling process. In total APCI has constructed and installed 57 trains of which some are not yet operating.

There are four other proprietary methods. Philips together with Bechtel market the Cascade process. This process was developed for the world´s second LNG liquefaction plant at Kenai, Alaska which started operations in 1969. Since then, Philips/Bechtel has stayed out of the LNG construction business until the start up of the Atlantic LNG project in Trinidad in 1999.

The first LNG liquefaction plant at Arzev, Algeria in 1964 was outfitted with the Prico technology of Black and Veatch Pritchard. To our knowledge the Prico technology is used only at Arzev and at Skikda, Algeria for the 1981 installation (phase II), in total 6 trains.

In the beginning of the LNG liquefaction market, Technip also had their own process; the Teal process. It was used for the phase I installation at Skikda. Technip has later joined in a strategic alliance with APCI, and are no longer in the business of marketing their own process.

In recent years the German company Linde and Shell, with their Dual Mixed Refrigerant (DMR) process, have also entered the LNG liquefaction market with their own technologies. The Linde process is to be used for the extension of the liquefaction capacity at the Burrup, Northwest shelf, Australia, starting deliveries in 2004. In addition, the Linde process will also be used at Snøhvit, Norway, which is scheduled to start delivering LNG from 2006. The Shell DMR process will be first used for deliveries from the Sakhalin II LNG plant, eastern Russia, from 2007 (See for instance Thomas (1997) and Shukri (2004) for more on the different methods).

To sum up; in the sixties and in the early seventies, the world's first five LNG plants used four different technologies, supplied by four different engineering firms. Then, during the rest of the seventies, the eighties and until 1999, only the APCI technology was installed except from the installation in Skikda, phase II by Prico. In the late 1990´s Philips reentered the market, shortly followed by new designs from Linde and Shell, and the developers of LNG plants again have four different firms and liquefying technologies to choose from.

Why were there four firms initially, and later only one firm for a period of nearly thirty years? This has puzzled us a lot, and made it necessary to test two alternative models of LNG liquefaction costs incorporating theories of mark-up pricing.

4 Factors influencing the price of LNG liquefaction capacity

An LNG liquefaction unit is created as the result of a large and complicated construction project. Actual construction typically takes several years, and involves extensive engineering work. The following factors will be crucial for total construction costs:

4.1 Infrastructure

In addition to the liquefaction plant, well and pumping equipment at the gas field, pipelines from the gas field to the liquefaction plant and harbour facilities for storage and loading LNG on to the LNG ships, need to be designed and built. Some of these costs, particularly onshore facilities directly related to the LNG plant, are sometimes included in the official cost figures, and make it necessary to control for these other cost factors. However, we lack detailed data on all the cost components, and are not able to include this into our regressions directly.

4.2 Number of trains/capacity on trains

A liquefaction plant has a certain capacity, commonly measured in million tons natural gas processed per year. Taking into account that a liquefaction plant has a certain optimal lifetime, the lifetime capacity of the plant should of course not exceed the total amount of gas resources available at the site. On the other hand, we are more prone to believe that downstream market conditions have put an upper bound on total capacity limiting the utilization of potential scale advantages.

There may be economies of scale connected either to the total capacity of the plant or to the capacity of each train making up the plant. Since a train nearly is a complete plant, we would expect eventual scale advantages in liquefaction *per se* to be connected to train size. Older facilities tend to have trains with lower capacities, but still more than one train. If there were scale advantages to train size, we are puzzled with respect to why each train was not made bigger. One reason could be that facilities made up of more trains are likely to have less supply problems, that is, if one train is down, the plant can still process LNG from the other trains.

Another reason could be that later technological advances have made it possible to make gradually bigger trains. It is argued that increased gas turbine efficiency combined with larger turbine units have reduced the number of gas turbines needed in LNG plants by half since the industry start-up (see Troner (2001)). This may have made it easier to build larger trains.

4.3 Organizational learning

There are 20 export plants currently in operation or under construction. At many of these sites additional trains have been added many years after the start up date. With respect to trains, there are at present 80 trains in operation or under construction worldwide, see EIA (2003). Our hypothesis is that organizational learning with respect to constructing and building a liquefaction train takes place each time a train is built, independent of whether the train is added to an existing plant or the train is set up on a greenfield site. Further, we conjecture that the capacity of the train does not influence learning, that is, learning reduces liquefaction costs by the same rate independent of train size.

Clearly, some sort of learning also takes place while running a liquefaction plant. One example could be the experience gathered with the Philips, Kenai plant from 1969. Although this plant has only one train, it has operated at more than 95% of capacity for more than 30 years, maybe making it more acceptable for today's buyers of LNG production technologies to rely on one train facilities.

Another example could be the reduced need for design redundancy. The dominant Asian LNG market has historically focused more on security of supply than other regional markets e.g. LNG is and has been Japan's only source of natural gas imports. Consequently, LNG greenfield projects in the Asian region have historically been planned using ample capacity margins and redundant design features in order to assure security of supply and the ability to meet its contract supply obligations. Experience with production of LNG may however have decreased the need for design redundancy, and hence, reduced the capital costs of later trains.

4.4 Experience induced process R&D

There is much writing about technological advances in the literature about the LNG business, however, we have not discovered examples of major technological breakthroughs in the history of LNG. Neither have the LNG history shown any important difference in thermodynamic efficiency between the different liquefaction technologies (see Troner (2001)).

Many of the inventions seem to be of a process nature, that is, they have gradually reduced running costs. A steady decrease in power requirements may be the most apparent development of this kind. The power requirement for the world's first base load LNG plant at Arzew, Algeria was 509kwhrs/tonne LNG, while the power requirement at current installations are around 250-330 kwhrs/tonne LNG. This has happened through evolution of compressor design and advances in turbine drivers.

At the ongoing Snøhvit installation, Norway, this process may have been taken even further by using electric powering of compressors with on site CCGT generation of electricity instead of compressors with direct gas turbine drive, see www.statoil.com. This should improve energy efficiency even further, and hence a given gas reserve can last longer and produce more LNG for sale. However, because our focus is on capital cost of liquefaction, our study will not pick up such changes.

4.5 Autonomous technological change

As already mentioned, some of the technologies used for LNG liquefaction, have improved independent of the development of the LNG business. One example is gas turbine technology, and we would expect materials technology to have improved in general. We aim to pick up this effect by including a time trend in our experience curve model.

4.6 Competition between suppliers of liquefaction technology

As in most other experience curve studies, we do not possess actual cost data, but data about the price paid by the buyer of the object under study. This implies that we must take into consideration that the price for an LNG liquefaction unit may include a mark-up. As already described in some detail, the number of competing technologies has varied a lot since the start of the LNG business. It is therefore also likely that the intensity of competition and the mark-up have varied considerably. We explicitly include a mark-up in our model. Further, we test two alternative formalizations of the mark-up. This is described in more detail in section six below.

4.7 Output prices

The price on LNG has tended to follow the price on oil, mostly as a formal link in bilateral trade contracts. LNG may be regarded as a substitute for oil; both can be used as input to the chemical industry, to heat buildings, to produce electricity etc. Hence, to the extent that a higher oilprice leads to increased demand for LNG, the downstream price of LNG may follow as observed. Up-stream, the suppliers of LNG liquefaction technology may have used this as an opportunity to increase their mark-up. This is treated in more detail in section six below.

4.8 Other factors

In addition to the factors mentioned, there are clearly a lot of other factors influencing costs. Environmental/safety regulations may be important. In many cases, innovations that reduce running costs, also reduce the environmental impact. Since energy for liquefaction is provided from burning natural gas at the site, an LNG facility emits large amounts of greenhouse gases like CO_2, and local pollutants like nitric oxides etc. By improving energy efficiency, the emission intensity of the liquefaction process is also reduced. In fact, we may have that the quest for energy efficiency and reduced emissions drives capital costs up.

We do not include a variable aiming to pick up the effect of environmental/safety regulations. Hence, we should not be particularly surprised if capital cost is influenced only weakly or even positively from a time trend aiming to pick up technological improvements since environmental/safety regulations are likely to have been strengthened through time. On the other hand, in a study of five different LNG projects, DiNapoli and Yost (2003) found no relationship between low environmental impact and high capital costs.

Prices on central inputs may have increased more or less than the price index we use to inflate historical prices, and by this lead to biased estimates of what is driving LNG liquefaction costs. According to OMAN LNG, the two train facility at Qalhat involved 10,000 tons of steel, 40 million man hours of construction time and some 100,000 cubic meters of concrete for the foundation alone. Even though 40,000 tons of steel sounds impressive, the steelcost would with current steel prices make up less than 1% of total capital costs. Construction time is more important. The expenses related to both financing and insurance as well as personnel wages are accumulating for each day of construction. We would therefore have liked to adjust for spatial and time related differences in financing costs and pay to construction workers, however, we miss data to correct for these possible effects.

According to our sources, the properties of the feed gas is also a significant cost issue. Large amounts of sulphur in the feed gas require removal and recovery facilities. Similarly, large amounts of CO_2 also require its own removal facility. As far as we know, the Snøhvit LNG factory in Norway will be the first LNG liquefaction facility for which the CO_2 is not only removed, but also pumped back into the geological structure containing the natural gas.

5 Data and data sources

Collecting cost data for LNG liquefaction units has been a long and cumbersome process. Since there exists no public database of LNG liquefaction costs, we have had to rely on occasional articles in Petroleum Economist, World Gas Intelligence and the Oil and Gas Journal. Book publications as "The Fundamentals of the LNG Industry" (Petroleum Economist (2001)), various internet press releases from the different technology licensors and all kinds of newspapers, as well as talks with key persons in the LNG business, also proved to be valuable sources for information about capital costs.

In particular, we have gone through all the issues of the Petroleum Economist from 1955 up to the current date. Cost data about LNG liquefaction have mostly appeared there, in cover stories about *new* LNG projects. These articles were often written before the LNG liquefaction unit had begun operating, but nearly always after the project had been agreed. Hence, many of our cost data must be viewed as *ex ante* estimates, and not the actual accounted costs. On the other hand, for many of the datapoints, we have *ex post* confirmation, that is, the same cost is reported in a later article, in a book etc.

Each LNG project is regarded as one cost observation, however several projects in our dataset consist of construction of more than one production train. In those cases we divide the total project cost figures on the number of trains installed to calculate average train capital costs.

In order to estimate organizational experience effects, the data set must be sorted as a time series. In case our data are reported after start-up, we use the time of LNG plant start-up as the sorting measure. On the other hand, if the cost data is an estimate from an articled published before start-up, we use the publication date. [2]

In addition to estimating organizational experience effects, we also use the dates to investigate whether a time trend picking up general technological change has influenced costs. In order to estimate the time trend more

[2] This is not a big point, because such a sorting principle yields almost the same sorting of datapoints as the sorting that would have resulted from using only the dates that the liquefaction units came into operation.

correctly, we constructed a "year-counter" based on our start-up- or publication date informations. This "year-counter", based on total months elapsed since the prior LNG plant observation, divided by 12, for all the observations, provides the exact relative difference in time between each data observation.

All price data, apart from two observations, are in current U.S. $. We have taken all figures and inflated to 2003 U.S. $ by using the consumer price index inflation calculator served by the US Department of Labor. We also have one observation in English £, and another in French Francs. In this case we have transformed it into U.S. $ by the exchange rate at that time, and inflated it afterwards.

Table 1 presents the two main descriptive statistics i.e. *average capacity cost* and *average train size.*

Table 1 "Descriptive statistics"

	billion $/*mty*	*mty* (capacity on trains)
Mean	0.3231	2.6918
Std.	0.1305	1.2994

The main puzzle with the dataset is the low costs for the first five facilities. Today, the Philips Atlantic LNG plant at Trinidad is viewed as the state-of-the-art liquefaction plant. The plant began operating in 1999, had only one train with a capacity of 3.2 million tons LNG per year, and liquefaction capacity cost of 0.244 billion $ per mty (million tons per year), that is, well below the mean cost of capacity as given in Table 1, and well above the mean train size also reported in Table 1. These figures should be compared with the first five LNG liquefaction installations:

Table 2 "The first five installations"

Site	Start up	Technology	Trainsize	bill.$/mty 1)
Arzew, Algeria	1964	Prico	0.37 *mty*	0.219
Kenai, Alaska	1969	Philips	1.40 "	0.203
Marsa El Brega, Libya	1970	APCI	0.65 "	0.163
Skikda, Algeria	1972	Teal	1.10 "	0.235
Lumut, Brunei	1972	APCI	1.06 "	0.253

1) All figures are in 2003 U.S. $

Observe that all capacity costs are below the mean cost, and further, that the train sizes are very small.

After Lumut, Brunei, no new facility was built until 1977 in Abu Dhabi, and then at a considerably higher capacity cost; 0,414 bill. $/mty. All observations above are based on capital cost estimates for liquefaction alone.

Further, for many of the observations we have multiple sources (see for example DiNapoli (1986) and Thomas (1997)). Differences in observed capacity cost, may not only stem from differences in real costs, but also from differences in mark-up pricing. Hence, we need to look further into the possible mark-up in selling liquefaction plants.

6 The Mark-Up on LNG liquefaction

6.1 Upstream Cournot competition

In order to analyze factors which are likely to determine the size of the mark-up, we will present a formal model. With respect to our data set, we are especially interested in to what extent the mark-up is linked to the oil price and to the number of firms supplying LNG liquefaction technology.

LNG is mostly traded in long term contracts specifying both sales volume and price. The sellers of LNG are in most cases consortia in which the owner of the gas resource has a major share. Hence, we may assume that eventual resource rent is collected downstream, and not upstream on the input price of the feed gas. For each liquefaction unit, the consortium owning the unit, normally sells to more than one buyer. The buyers are typically national gas companies using LNG to supplement their supply of piped natural gas, power plants using LNG to produce electricity, or industry using LNG as input in the production process.

We will look at the price formation of LNG liquefaction capacity in a Cournot game. The point of departure for constructing the demand schedule for LNG liquefaction capacity is each particular LNG project. For each project the initiators of the LNG project i.e. the LNG consortium, meet with the potential buyers of LNG and agree on the volume/price *given* the price on LNG liquefaction capacity.

We assume that the number of LNG projects in each time period is exogenously given. Further, that the suppliers of LNG liquefaction technology compete simultaneously for all the projects in that time period. Thus, in the Cournot game suppliers of LNG liquefaction units compete *given* the demand schedule for LNG liquefaction capacity from all the projects in the time period. While the number of projects is exogenous, the scale of each project depends on the LNG liquefaction capacity price.

Assume that the end-user demand for LNG is given by the following linear demand function:

$$x^d = a - bw_l + dw_o, \tag{2}$$

where x^d is total demand for LNG, w_l is the price of LNG at export terminal, w_o is the price of oil, and where a, b and d are constants/parameters. The demand function should be interpreted as a *residual demand function*, that is, demand given that we have full capacity utilization of piped natural gas to the region.

Each LNG consortium acts as a monopoly. Hence, it maximizes:

$$\omega = [w_l - \rho]\,[a - bw_l + dw_o] - \sigma_\kappa, \tag{3}$$

where ρ is cost per. unit LNG capacity at export terminal (liquefaction), and σ_κ is site specific infrastructure costs. The first order condition for profit maximum yields, after some rearranging, the price of LNG:

$$w_l = \frac{a + dw_o + b\rho}{2b}. \tag{4}$$

Data from IEA (2001) shows that the price of LNG has indeed tended to follow the oil price. By inserting the price from (4) into the demand function (2), we find the supply x_s from the consortium:

$$x_s = \frac{a - b\rho + dw_o}{2}.$$

Total supply of LNG depends on how many LNG projects that are completed by different LNG consortia in a given time period. Assume that Γ LNG projects are currently being completed. Total demand for LNG capacity is then given:

$$x_s^T = \sum_{\kappa=1}^{\Gamma} \frac{a^\kappa - b^\kappa \rho + d^\kappa w_o}{2}$$

Assume that $a^\kappa = a$, $b^\kappa = b$ and $d^\kappa = d$ for all projects. We then get the following inverse demand function for LNG capacity: $\rho = \frac{a+dw_o}{b} - \frac{2}{b\Gamma} x_s^T$. There are m suppliers of LNG liquefaction technology currently being active. We further assume that they play a one shot Cournot game given the total demand for LNG capacity. Let $x_s^T = \sum_{i=1}^{m} x_i$. We then have that each LNG liquefaction supplier i maximizes its profit π_i:

$$\pi_i = \left\{ \left[\frac{a + dw_o}{b} - \frac{2}{b\Gamma} \sum_{i=1}^{m} x_i \right] - c_i \right\} x_i$$

where c_i is the capacity cost of LNG liquefaction. The first order conditions are:

$$\frac{\partial \pi_i}{\partial x_i} = \left[\frac{a + dw_o}{b} - \frac{2}{b\Gamma} \sum_{i=1}^{m} x_i \right] - c_i - \frac{2}{b\Gamma} x_i = 0, \; \forall i.$$

We assume symmetric LNG liquefaction technology suppliers i.e. $c_i = c$, $\forall i$. The first-order conditions are then easily solved:

$$x_i = \Gamma \frac{a + dw_o - bc}{2(m+1)}. \tag{5}$$

And we get the price of liquefaction capacity:

$$\rho = \frac{1}{m+1}(\frac{a+dw_o}{b}) + \frac{m}{m+1}c, \tag{6}$$

and the mark-up over costs:

$$\frac{\rho - c}{c} = \frac{1}{m+1}\left[\frac{a+dw_o}{bc} - 1\right] \tag{7}$$

Note that while the oilprice increases the mark-up, the number of LNG liquefaction suppliers decreases the mark-up.

Further, note from (5) that total supply of LNG liquefaction capacity, that is $mx_i = x_s^T = m\Gamma\frac{a+dw_o-bc_i}{2(m+1)}$, increases when the price of oil increases. Looking to our dataset and the number of new LNG facilities in the period 1977 to 1984, it does seem like the supply of LNG liquefaction capacity increased slightly some years after the oil-price shock in 1973.

On the other hand, equation (7) is not suitable for our econometric experience curve model. We will therefore test a variant of (7), see the next section.

6.2 "War of attrition"

The models above do not actually answer the question posed at the end of section five: Why were there four firms initially supplying liquefaction technology, and later only one firm for a period of nearly thirty years? Hence, we will also briefly look at a second alternative. Assume that instead of Cournot competition in which all liquefaction technology firms may make positive profit before fixed costs, the LNG liquefaction firms play a Bertrand game, and that the different technologies are perfect substitutes (see for instance Troner (2001) which states that there is no important difference in thermodynamic efficiency between the different liquefaction technologies). This implies that when $m \geq 2$, the price will be equal to marginal cost of liquefaction capacity i.e. $\rho = c_i$. To the extent that liquefaction firms also have fixed costs, they will all have negative profits, and we get a "war of attrition" from which only one firm can survive, and continue to supply liquefaction technology (see Tirole (1997), page 311-314).

Then, when all firms except one have left the business i.e. $m = 1$, we assume that the price on LNG liquefaction is set as above, that is, the owner of the remaining LNG liquefaction technology acts as a monopoly. This implies that the liquefaction capacity price ρ is given:

$$\rho = mu(w_o) * c_i \text{ (for } m = 1\text{)},$$

where $mu(w_o) > 1$ is the mark-up as a function of the oilprice.

The constant mark-up is assumed to hold for all observations from 1977 until 1999. In this period only APCI supplied liquefaction technology except from one case. For the years from 1999 on Bechtel, Linde and later Shell entered the liquefaction market with their proprietary technologies, and hence, the companies will in the Bertrand model enter a new round of fierce competition through the "war of attrition".

7 The liquefaction cost model

Basically, we treat our dataset as 40 observations of the same cost function in different points in time. Because different technologies may differ with respect to cost structure, we control for the two historically main technologies; APCI and Philips/Bechtel, by using dummies. The four other technologies, Prico, Teal, Linde and Shell, are in the dataset represented by one or two observations respectively, and will be embodied in the constant term. Organizational learning is an argument in the cost function which varies according to time. We assume that learning is industry wide, and that liquefaction firms are myopic i.e. they set the price on liquefaction capacity based on current unit cost.

The previous discussion suggests that the price of an LNG liquefaction unit may for all or some periods exceed the costs. Let ρ_t denote the price on LNG liquefaction capacity recorded for a liquefaction installation t measured in \$ per $mt/year$. We then formulate the following log linear model:

$$\ln \rho_t = \alpha_0 + \ln mu_{tj}(w_t, m_t) + \alpha_1 g_t + \alpha_2 d_{Phil} + \alpha_3 d_{APCI} \tag{8}$$

$$+\alpha_4 \ln (Q_t) + \alpha_5 \ln \left(\frac{q_t}{n_t} \right) + \alpha_6 \left(dat_t \right) + u_t$$

The liquefaction unit t may consist of trains that are added to an existing facility, or one or more trains built on a greenfield site. The other variables are as follows:

$mu_{tj}(w_t, m_t)$ = the mark-up in model alternative j (see specification below). The arguments of the mark-up function are w_t; a moving average of the oilprice for the last five years, and m_t; the number of competing LNG liquefaction technologies being marketed at the time of a final construction agreement. It is of course difficult to measure the latter variable. Even though the APCI technology seems to have dominated the LNG liquefaction market for the whole period from 1972 to 1999, we do not know to what extent it has been constantly challenged by the other technologies.

g_t = a dummy adjusting for infrastructure cost. The variable g_t takes the value 0 if our observation includes only liquefaction plant capital costs, and the value 1 if our cost observation also includes other cost factors than the mere liquefaction unit. Of a total 40 cost observations 10 include total cost figures. These are typically greenfield facilities, often involving pipelines from the gas field, as well as storage and loading facilities. Clearly, using a dummy in order to pick up such cost differences is a rude measure, however, we lack data to refine the measure further.

d_{Phil}, d_{APCI} = dummies specifying the liquefaction technology. Since we only have one or two observations for the other technologies respectively, these technologies are treated together as the last category.

Q_t = accumulated LNG liquefaction trains built at the time of train t. As mentioned, we measure organizational learning as accumulated experience with the building of new liquefaction trains. Our point of departure is that learning has been industry wide.

$\left(\frac{q_t}{n_t}\right)$ = total capacity of facility t divided by the number of trains at facility t. This variable is intended to pick up eventual scale advantages in liquefaction. Clearly, there may be scale advantages connected to infrastructure and total capacity of a facility. On the other hand, our focus is on liquefaction cost *per se*, and we have therefore sought to separate liquefaction costs from infrastructure costs.

dat_t = date of start-up/date of publishing of cost data. In addition to being a measure to sort the observations, we also use the date of start-up/date of publishing of cost data, earlier explained as the "year-counter", in order to identify any time trend suggesting some form of technological development, or other kind of development.

Lastly, $\alpha_h, h = 1, ...6$ are parameters.

We will use the following expressions for the mark-up:

$$mu_{tj}(w_t, m_t) = \begin{matrix} [w_t]^{\beta_1}\,[m_t]^{\beta_2} \text{ for } & j = 1, t = 1, ..., 41 \\ 1 & \text{for } j = 2, t = 1, ..., 5; 23, ..., 40 \\ [w_t]^{\beta_3} \exp^{\beta_4} \text{ for } & j = 2, t = 6, ..., 22 \end{matrix} \tag{9}$$

where $\beta_k, k = 1, ...4$ are parameters. The notation $j = 1$ denotes Cournot competition, while $j = 2$ denotes Bertrand competition. The rationale behind these alternatives are outlined above. We have chosen to model the mark-up as simple as possible making the effect of the oilprice and the effect of the number of competitors separable.

Our data set consists of 40 observations of capacity costs of which 10 includes infrastructure and the rest is given for liquefaction only. The error term u_t is assumed to be normally distributed with $\sim N(0, \sigma_t)$. Due to the different character of our cost observations, that is, some are *ex ante* estimates, others are historical costs, some include infrastructure, many do not etc., we do not assume constant variance.[3] Consequently, we will use WLS - weighted least squares using OLS residuals - as our estimation method. The estimations are carried out in PcGive with use of the special panel data package.

[3] This was confirmed by initial estimations using the OLS method, which lead us to reject the H_0-hypothesis of homoscedastisity within our dataset.

8 Estimation results

We started with a full dataset estimation of the whole model, labeled Model 1, using the alternative $j = 1$ expression for the mark-up. That is, the market actors play a one shot Cournot game incorporating both the oil price and the number of competitors in their quantity setting behavior. Next we ran a series of estimations removing non-significant variables successively. The results are displayed in Table 3 below.

Table 3 "WLS on the whole dataset"

	Model 1	**Model 2**	**Model 3**	**Model 4**	**Model 5**
α_1	0.1668** (0.0655)	0.1767*** (0.0612)	0.1786*** (0.0620)	0.1629*** (0.0594)	0.1668*** (0.0596)
α_2	-0.1380 (0.0929)	-0.1432 (0.0911)	-0.0649 (0.0708)	-	-
α_3	-0.1160 (0.0968)	-0.1255 (0.0935)	-	-	-
α_4	0.1189 (0.1367)	0.1560 (0.1101)	0.1108 (0.1061)	0.1208 (0.1052)	-
α_5	0.0679 (0.1451)	-	-	-	-
α_6	-0.0136* (0.0068)	-0.0129* (0.0065)	-0.0108* (0.0064)	-0.0117* (0.0063)	-0.0049** (0.0022)
β_1	0.1212* (0.0687)	0.1173* (0.0673)	0.1292* (0.0676)	0.1254* (0.0761)	0.1481** (0.0646)
β_2	-0.3721*** (0.0619)	-0.3646*** (0.0590)	-0.3344*** (0.0552)	-0.3529*** (0.0513)	-0.3771*** (0.0470)
R^2	85.5 %	85.4 %	84.6 %	84.2 %	83.6 %
n	40	40	40	40	40

Standard errors in parentheses, * 90% level of significance, **95% level of significance. ***99% level of significance.

As can be seen from Model 1, only the infrastructure cost dummy, the time trend variable, the oil price and the number of competitors came out significant at a 90 % level or more in the full dataset estimation covering all variables. This implies that we did not find any evidence of systematically different pricing of technology between APCI or Philips and the other technologies available through time. From this we might assume that there have been no real difference in construction costs between plants using the two leading technologies and plants using alternative technologies, however the data sample for the alternative technologies are modest.

Next, and more importantly, we didn't find any significant effects from either experience or scale on liquefaction plant capacity pricing. However, as one would expect, we discovered a strong time related positive correlation both between accumulated trains and train capacity and each of them combined with the time trend variable, which would weaken their respective partial regression coefficients in the estimations. Still, we found evidence of a robust significant time trend influencing LNG plant pricing, which may stem from an anticipated general technological development.

The lack of significant findings from both learning- and scale effects are somewhat surprising, as these factors are often related to new technology developments. Particularly the steady increase in single train capacities has commonly been associated with the falling costs of LNG capacity. In addition, as the technology has matured and more experience is gained, it is likely that the need for ample capacity design margins has gradually diminished.

The significant impact from both the oil price and the number of suppliers of different technologies on the mark-up pricing behavior was expected according to our formal model, shown in section six. Particularly competition seems to have had a strong impact on LNG liquefaction capacity pricing, as we find both a high coefficient value and a high level of significance for the effect on capacity pricing from the number of competitors at each point in time.

The key findings from the full dataset estimation were further strenghtened by additional estimation results, where non-significant variables were removed successively, labeled Model 2-Model 5 in table 3. The time trend effect is rather weak though in all regressions. Based on model 5, the yearly decrease in liquefaction capacity pricing due to the time trend was about 0,5% per year in the period 1970 to 1999. On the other hand, the greenfield effect is rather strong. Compared to adding a new train to an existing facility, the cost of capacity increases by about 17% if a liquefaction train is installed at a greenfield site.

8.1 Firm specific learning

In order to look more into learning and competition we also ran WLS estimations on two sub samples, one consisting of the APCI liquefaction trains only and one sample also including the Philips technology trains. As APCI has been the dominant producer of liquefaction technology since the early 1970´s, delivering 59 out of a total 81 trains in our dataset, we may find that APCI has developed a technology-specific experience with respect to their production costs. As the Philips technology also has been present both in the early stage of the LNG industry as well as in the later years, it is also interesting to control for any price differences between these two leading technologies. Starting with the APCI dataset we could remove the technology dummies α_2 and α_3, and the results from the estimations are reported in Table 4 below, labeled Model 6 and 7. The results from the estimations using the APCI/Philips dataset are labeled Model 8 and 9 in Table 4.

Table 4 "WLS on the APCI/Philips dataset"

	Model 6	Model 7	Model 8	Model 9
α_1	0.1519* (0.0846)	0.1711** (0.0779)	0.1795** (0.0693)	0.1721*** (0.0593)
α_2	-	-	-0.0609 (0.0876)	-
α_3	-	-	-	-
α_4	0.4340 (0.3685)	0.6255** (0.2474)	0.4828 (0.3330)	0.6183** (0.2307)
α_5	0.1190 (0.1832)	-	0.0447 (0.1626)	-
α_6	-0.0279* (0.0136)	-0.0313*** (0.0110)	-0.0267** (0.0128)	-0.0307*** (0.0104)
β_1	0.0476 (0.0879)	-	0.0665 (0.0844)	-
β_2	-0.3805*** (0.0699)	-0.3692*** (0.0637)	-0.3539*** (0.0655)	-0.3808*** (0.0507)
R^2	85.5 %	85.0 %	85.9 %	85.3 %
n	26	26	35	35

Standard errors in parentheses, * 90% level of significance, **95% level of significance. ***99% level of significance.

The results from both sub sample estimations are generally similar to the full dataset estimations, that is the infrastructure dummy, the time trend and the number of competitors seem to have a robust significant effect on the unit price of an LNG production train. The results thus strenghten our earlier findings that indicate oligopolistic LNG liquefaction plant pricing. Moreover, the effect from the oil price is still positive, but no longer significant, as was the case in the full dataset estimations.

Interestingly, both the experience and scale coefficients came out positive in all estimations, including the full dataset. Rather controversially, for both the sub samples the experience effect was even significant at a 95% level, that is experience increases costs! We believe that these highly atypical results may stem from some unknown factor, possibly related to the mark-up pricing element. Allover, these findings strenghten the arguments against the hypothesis of extended experience effects within LNG liquefaction construction costs. We therefore doubt that any experience has taken place with respect to construction costs of the APCI-licenced LNG plants. With respect to any possible differences between the APCI and the Philips liquefaction technology, the estimations provided no significant findings of differences in the pricing behavior.

8.2 War of attrition

To elaborate on our earlier findings regarding both experience effects and monopoly power, we also tried the alternative mark-up model on the full dataset ($j = 2$ in $eq.(10)$). Using the Bertrand-competition-based mark-up we a priori assume that the low unit prices for both the first LNG plants and plants in recent years was a direct result of fierce competition through marginal cost pricing. This may bring forward possible experience effects in a better way compared with the earlier model estimations. We continued the same estimation procedure of removing variables successively, and the main results are presented as Model 10-12 in table 5 below.

Table 5 "Alternative model of mark-up"

	Model 10	**Model 11**	**Model 12**
α_1	0.1667** (0.0753)	0.1482** (0.0665)	0.1504** (0.0667)
α_2	-0.1155 (0.1053)	-	-
α_3	-0.0637 (0.1076)	-	-
α_4	0.1476 (0.1546)	0.1343 (0.1169)	-
α_5	0.0013 (0.1619)	-	-
α_6	-0.0122 (0.0078)	-0.0119 (0.0071)	-0.0042* (0.0025)
β_3	0.1243 (0.0785)	0.1241 (0.0750)	0.1474** (0.0726)
β_4	0.4459*** (0.0958)	0.4585*** (0.0800)	0.4976*** (0.0728)
R^2	81.5 %	80.8 %	80.0 %
N	40	40	40

Standard errors in parentheses, * 90% level of significance, **95% level of significance. ***99% level of significance.

With respect to the main findings from the earlier full model estimations, the alternative mark-up model performs much the same. That is, we find neither a significant experience effect nor a scale effect on LNG plant unit costs, while the oil price, a time trend and particularly a dummy (β_4) taking the value 1 in periods with mark-up pricing, show robust and significant characteristics. Thus, in all of our full model estimations, irrespective of mark-up model, the number of competitors stayed significant above a 99% level, hence, rivalry between different liquefaction technologies seem to have had a robust influence on LNG plant capacity pricing over the years.[4]

9 Conclusion

Our study casts doubt on the belief that there has occurred experience effects with respect to the capital costs of LNG liquefaction facilities. Our conjecture is that the total number of LNG trains is still to few, and the construction too spread out over a long time period to foster any significant experience effects in liquefaction technology production. Alternatively, the huge financial risks involved in an LNG project may have delayed major technological developments. As the liquefaction technology proved itself reliable, the risks involved in new technologies and possible delivery failures may have been greater than the possible cost advantages from improved technology and more effective production.

Another, and maybe more plausible explanation, is that the relatively weak competition in much of the history of LNG has weakened the incentives for technology improvements. The fact that one company, APCI, has appeared to control the business for nearly 30 years, may well have eased their efforts of cost reductions. Indeed, it seems like the unit price of an LNG plant has fallen after the return of the Philips/Bechtel technology in 1999 and the introduction of the Shell and Linde technology later on. However, this finding may be a consequence of shrinking mark-ups rather than cost reductions, which is also supported by our estimation results. We generally find robust and significant evidence of mark-up pricing in all of our model simulations. Hence, the apparent fall in LNG liquefaction construction costs the last decade is most likely to originate from increased competition between different liquefaction technologies.

If our model draw the right conclusions it is not reasonable to believe that the current cost reductions will continue in a longer term, as the price of LNG plants sooner or later will approach marginal costs of production. However, competition in itself may trigger technological change, and only after we have seen a substantial number of new LNG projects come on stream, we may draw more robust conclusions with respect to where we are on the LNG plant construction experience curve.

[4] In order to investigate even further a possible experience effect within our dataset we also estimated a model where we assumed some sort of tacit collusion among the LNG technology suppliers after the reintroduction of the Philips technology. That is, we assumed that they didn't restore to marginal cost pricing, but kept the monopoly price. This model, however, provided almost identical results as compared with our formal Bertrand competition model. Not surprisingly, our tacit collusion model also showed considerable lower explanatory power.

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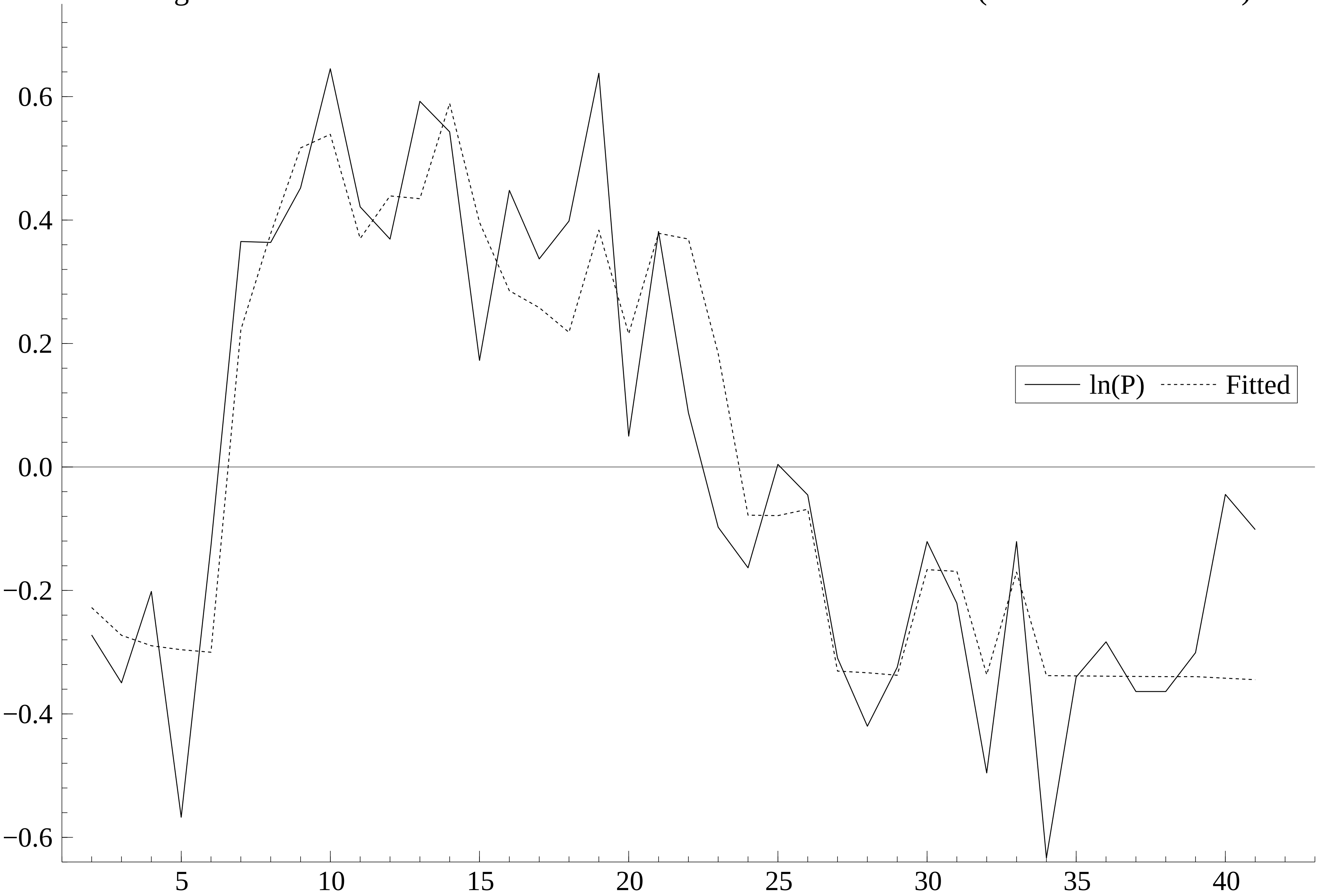
Appendix

Table A1. LNG plant dataset

	LNG plant	Country	Start-up	Technology	# trains	Capacity/ train (mty)	Capital unit costs (2003$ bn/mty)
1	Camel, Arzew GL 4Z	Algeria	1964	Prico	3	0.37	0.219
2	Kenai, Alaska	USA	1969	Phillips	2	0.70	0.203
3	Marsa El Brega	Libya	1970	APCI	4	0.65	0.163
4	Skikda, Phase 1	Algeria	1972	Teal	3	1.10	0.235
5	Lumut	Brunei	1972	APCI	5	1.06	0.253
6	Adgas, Das Island	Abu Dhabi	1977	APCI	2	1.50	0.414
7	Arzew, GL 1Z	Algeria	1978	APCI	6	1.21	0.415
8	Arun, Phase 1	Indonesia	1978	APCI	3	1.40	0.532
9	Arzew GL 2Z	Algeria	1981	APCI	6	1.27	0.439
10	Bontang, Phase 2	Indonesia	1983	APCI	2	2.00	0.416
11	MLNG I, Bintulu	Malaysia	1984	APCI	3	2.00	0.495
12	Arun, Phase 2	Indonesia	1984	APCI	2	1.65	0.505
13	Arun, Phase 3	Indonesia	1986	APCI	1	1.50	0.342
14	Burrup Northwest Shelf	Australia	1989	APCI	2	2.00	0.452
15	Adgas, Das Island 3	Abu Dhabi	1994	APCI	1	2.30	0.450
16	MLNG II (Dua)	Malaysia	1995	APCI	2	2.60	0.403
17	Qatargas, T1+2	Qatar	1997	APCI	2	2.00	0.545
18	Qatargas 3	Qatar	1998	APCI	1	2.00	0.303
19	Bontang, T7	Indonesia	1998	APCI	1	2.60	0.429
20	Bontang, T8	Indonesia	1999	APCI	1	2.95	0.261
21	Atlantic LNG, T1	Trinidad& Tobago	1999	Phillips	1	3.20	0.244
22	Bonny Island, T1+2	Nigeria	1999	APCI	2	2.95	0.421
23	Rasgas, T1+2	Qatar	1999	APCI	2	2.60	0.314
24	Qalhat, T1+2	Oman	1999	APCI	2	3.00	0.275
25	Bonny Island T3	Nigeria	2002	APCI	1	2.95	0.289
26	Atlantic LNG, T2+3	Trinidad& Tobago	2003	Phillips	2	3.20	0.175
27	MLNG III (TIGA)	Malaysia	2003	APCI	2	3.80	0.211
28	Burrup Nortwest Shelf, T4	Australia	2004	Linde	1	4.20	0.205
29	Damietta	Egypt	2005	APCI	1	5.00	0.208
30	Bonny Island, T4+5	Nigeria	2005	APCI	2	4.00	0.217
31	Idku ELNG, T1	Egypt	2005	Phillips	1	3.60	0.255
32	Atlantic LNG, T4	Trinidad& Tobago	2005	Phillips	1	5.20	0.231
33	Rasgas, T3+4	Qatar	2005	Philips	2	4.70	0.255
34	Qalhat, T3	Oman	2006	APCI	1	3.30	0.189
35	Darwin LNG	Australia	2006	Phillips	1	5.00	0.200
36	Idku ELNG, T2	Egypt	2006	Phillips	1	3.60	0.153
37	Snøhvit	Norway	2006	Linde	1	4.11	0.279
38	Tangguh	Indonesia	2007	APCI	2	3.50	0.200
39	Bioko Island LNG	Equatorial Guinea	2007	Philips	1	3.40	0.260
40	Sakhalin II	Russia	2007	SDMR	2	4.70	0.213

Figure A1: Actual and fitted values from the estimation of Model 5 (deviation from mean)



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