Issues in fuel cell commercialization [1]

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Abstract

After 25 years of effort, the phosphoric acid fuel cell (PAFC) is approaching commercialization as cell stack assemblies (CAS) show convincingly low degradation and its balance-of-plant (BOP) achieves mature reliability. A high present capital cost resulting from limited cumulative production remains an issue. The primary PAFC developer in the USA (International Fuel Cells, IFC) has only manufactured 40 MW of PAFC components to date, the equivalent of a single large gas turbine aero-engine or 500 compact car engines. The system is therefore still far up the production learning curve. Even so, the next generation of on-site 40% electrical efficiency (LHV) combined heat-and-power (CHP) PAFC system was available for order from IFC in 1995 at US$ 3000/kW (1995). To effectively compete in the marketplace with diesel generators, the dispersed cogeneration PAFC must cost approximately US$ 1550/kW (1995) in the USA and in Europe. At somewhat lower costs than this, dispersed cogeneration PAFCs will compete with large combined-cycle generators. However, in Japan, costs greater than US$ 2000/kW will be competitive, based on the late-1995 trade exchange rate of 100–105 Yen/US $). The perceived advantages of fuel cell technologies over developments of more conventional generators (e.g., ultra-low emissions, siting) are not strong selling points in the marketplace. The ultimate criterion is cost. Cost reduction is now the key to market penetration. This must include reduced installation costs, for which the present goal is US$ 385/kW (1995). How further capital cost reductions can be achieved by the year 2000 is discussed. Progress to date is reviewed, and the potential for pressurized electric utility PAFC units is determined. Markets for high-temperature fuel cell system (molten carbonate, MCFC, and solid oxide, SOFC), which many consider to be 20 and 30 years, respectively, behind the PAFC, are discussed. Their high efficiency and high-quality waste heat should make them attractive if technical progress and costs are acceptable. Commercialization of the proton-exchange membrane fuel cell (PEMFC) system is considered for stationary and mobile applications.

Keywords: Fuel cells; Commercialization; Phosphoric acid fuel cells

1. Introduction

Since fuel cells (FCs) have high theoretical thermal efficiencies, FC research and development has been aimed at commercial goals since the discovery of the hydrogen FC concept by Grove in 1839. Reviews of early work are available [1–3]. Mond and Langer [4] designed the first fuel cell resembling its modern counterparts, though its performance was severely limited by available materials with only 3.5 mA/cm² at 0.73 V on hydrogen and oxygen. They stated 'We prefer to work ··· with an e.m.f. of about 0.73 V, ··· which gives a useful effect of nearly 50% of the total energy of the

hydrogen absorbed in the battery'. At that time, a steam engine was little better than 5% efficient. As a measure of one century of progress, today's proton-exchange membrane FC (PEMFC) using a perfluorinated sulfonic acid polymer as the electrolyte can operate at a current density 300 times greater at the same cell voltage. Mond and Langer [4] also showed that a water gas derived from coal containing would operate the fuel cell, even if only for short times. In 1894, Ostwald [5] proposed that an electrochemical engine or fuel cell operating on clean fuel derived from coal would power the 20th century. In spite of his predictions, the FC remained a laboratory curiosity during the first half of the 20th Century. Steam power produced a.c. electricity, and the spark-ignition Otto cycle engine began to dominate the private transportation energy economy. Up to 1950, the history of the FC was mostly in the area of extending the ranges of possible electrolytes and operating temperatures. Temperature ranges were largely determined by available materials. It was realized that only certain types of electrolytes would operate

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[1] This is an updated version of a paper presented at the 1995 Asia–Pacific Economic Cooperation (APEC) Energy R&D and Technology Transfer Seminar, 14–17 February 1995, Seoul, South Korea. It is intended to complement the recent Executive Summary and full Report prepared for the US Department of Energy during 1993 and 1994 by the second Advanced Fuel Cell Working Group (AFCWG-2), of which the author was a member. The AFCWG-2 reports were published as Refs. [80a] and [80b].

satisfactorily with a given fuel and oxidant, such as hydrogen and oxygen. The range of electrolytes was determined by those in which the major conducting ion was produced in one electrode reaction and consumed in the other, to avoid problems associated with ionic concentration gradients [6].

Practical electrolytes for hydrogen-containing fuels with oxygen as oxidant include stable acids, aqueous alkalis, molten carbonates, and high-temperature solid oxides. They all have advantages and disadvantages. Acid systems required selected non-corroding conducting and structural materials, especially at the oxygen cathode, together with noble metal (platinum) catalysts. Alkaline systems (AFCs) are less demanding from the viewpoint of constructional materials and catalysts, but they cannot be used with fuels containing carbon compounds without purification to pure hydrogen, otherwise conversion to aqueous carbonate occurs. This seriously reduces performance, unless CO_2 is provided at the oxygen cathode and collected at the anode, so that aqueous carbonate becomes the transporter ion [6]. MCFCs operating in the 625-700 °C temperature window (determined by performance and ionic resistance limitations at the lower temperature, and by corrosion at the upper limit) must use the same approach. Finally, oxides may be used as conducting electrolytes, but no combination of stable molten oxides and suitable structural materials exists. However, certain solid oxides have acceptable properties in the 800-1000 °C temperature window. SOFCs use yttria-stabilized zirconia electrolyte, with nickel cermet anodes and doped conducting oxide cathodes, all with matched thermal conductivity.

By the late 1950s, the FC concepts which would (or more accurately, still may) be commercialized were beginning to emerge from the laboratory.

2. Early attempts at commercialization

2.1. The 1950s and 1960s

The cost of suitable stable materials for commercial fuel cells was always seen as a major issue. Another problem was the low power density of fuel cells, which resulted in high materials requirements per unit of output. The AFC must use pure hydrogen with oxygen or CO_2-free air. Hence, its commercial use on gases derived from common fuels seemed uneconomic, because of the perceived cost of producing pure hydrogen from such sources. However, Bacon and co-workers [7] proposed the use of hydrogen-oxygen AFCs with nickel-based electrodes and constructional materials operating at high temperature (≥ 200 °C) and high pressure to increase power density for energy load-leveling in the 1950s. In this concept, hydrogen and oxygen would have been produced from off-peak power by electrolysis. However, the concept failed the test of commercial competitiveness, since the cost of the electricity produced from the storage system would have exceeded that for conventional peak power production. By 1959 the Bacon cell was in a

much more advanced state than other FC electrolyte technologies, and it was licensed for space applications by a major manufacturer of aero-engines, the Pratt and Whitney Aircraft Division of United Aircraft Corporation (P&W). This company received the contract from NASA to develop the FC power supply for the Apollo Mission Service Module. This FC used a Bacon cell modified for zero-gravity applications, with a sealed (i.e., non-circulating) electrolyte operating at 4 atm pressure on pure hydrogen and oxygen. The pressure was reduced to save pressure vessel weight, and the performance was partially compensated by operation at about 260 °C. Under these conditions, cathode-side corrosion limited AFC life to the absolute requirements of the mission. It is no exaggeration to say that this FC technology, designated PC3A-2 (Power Cell Mark 3A-2) by P&W, was a key element making the manned lunar missions possible. Other technologies from the Apollo Program, e.g. integrated circuits, have revolutionized the world. The FC has yet to do so.

Transfer of Bacon's AFC technology to P&W led to engineering development of FC technologies for terrestrial and other applications, with emphasis on the use of common carbon-containing fuels or their derivatives. Laboratory work by Broers and Ketelaar [8] starting in the early 1950s in The Netherlands made the low-corrosion strong-base environment of the moderate-temperature Bacon AFC compatible with carbon-containing fuel gases by the use ion transfer via carbonate ion rather than hydroxide. This required a molten alkali carbonate electrolyte, with oxyen and CO_2 as the cathode reactants. This work was based on pioneering efforts by, e.g. Greger in the late 1930s, and Gorin in the early 1950s. In turn, these were based on early attempts to construct FCs directly using coal, starting with Jacques in the 1890s and Baur between 1910 and 1933 [1-3]. In the early 1960s, Netherlands MCFC technology was transferred to the Institute of Gas Technology, Chicago (IGT), the research arm of the American Gas Association. The objective was an FC which could operate directly or indirectly on natural gas (NG).

Elsewhere, attempts were made to use CO_2-rejecting acid electrolytes with high-surface area catalyst electrodes bonded by polytetrafluoroethylene (PTFE, Teflon®, Du Pont de Nemours and Company), which was discovered in 1938 and became available in the early 1950s. This proved to be a much more effective replacement for the hydrocarbon waxes used in early work [4]. The first work reported was at the General Electric Co. (GE) in the early 1960s, and similar electrodes were used at about the same time in non-CO_2-rejecting alkaline electrolyte at temperatures below 100 °C at the Union Carbide Corporation [1]. The Teflon®-bonded electrodes were most effective when used with electrolytes immobilized by capillary action in a stable powder matrix, as had already been used in 1889 [4]. Finally, embryo solid oxide technology based on work by Nernst and Wald [9] before 1900 emerged from the Westinghouse R&D Center in the early 1960s [10].

MCFC R&D in The Netherlands and at IGT was aimed at terrestrial consumer applications, but most early US work on other FC technologies was space- and defense-related. If feasible, direct hydrocarbon FCs operating at low to moderate temperatures [1] seemed to have major advantages. A CO_2-rejecting non-volatile acidic electrolyte would therefore be required. Early work showed that sulfuric acid lacked stability at the anode at about 90 °C, below which negligible direct hydrocarbon oxidation rates were obtained even with high platinum black catalyst loadings. No common electrolyte except phosphoric acid had the correct combination of materials properties for use at higher temperatures. However, its poor electrochemical kinetic characteristics for oxygen reduction on platinum required operation at 150 °C and beyond. This appeared to permit only gold, niobium, and tantalum as constructional materials. Phosphoric acid FCs (PAFCs) operating under these conditions were examined by GE in the early 1960s, though attempts to obtain satisfactory rates on direct hydrocarbon fuels proved unsuccessful [1]. Similar studies on the PAFC were conducted by developers at P&W, who realized that the high operating temperature of the PAFC made its anode relatively immune to poisoning by small amounts of CO present in hydrogen-rich gas feedstock, even though it was poisoned by the products of direct hydrocarbon oxidation. Such a gas mixture could be produced by steam-reforming NG, followed by water-gas-shifting to increase the overall hydrogen content of the feedstock and reduce its CO content to acceptable levels. The high operating temperature of the PAFC could provide excess steam for reforming, so extra fuel did not need to be burned for this application, increasing overall system efficiency. Dilute depleted anode gas was not wasted, since it could be used in the reformer burner. Finally, any further waste heat could be used for space-heating or for hot water.

The P&W engineering systems studies were conducted in 1965–1966, when space- and defense-oriented fuel cell R&D programs were winding down. There was then a general doubt that the development of sufficiently cheap FCs for terrestrial applications would ever be possible. By the late 1960s, GE FC programs for broad-based applications and at Union Carbide for electric vehicles were largely abandoned. In Europe (e.g., in France at Alsthom, working with Peugeot starting in 1968, and at the Institut Français du Pétrole, both for electric vehicle applications) enthusiasm was waning. The Netherlands' MCFC program was winding down. In this inactive environment, P&W made a proposal to the American Gas Industry in 1966 to develop a PAFC power system for individual households, which would provide all requirements for domestic power and heat. The individual homes would not be connected to the electric power companies' distribution system. If successful, these PAFC units would allow the gas companies to produce electricity on-site cheaper than delivered electrical power. A minority partner, IGT, was also involved to study the MCFC alternative, which had advantages of producing better quality waste heat, the ability to operate directly (via internal water-gas-shifting) on CO, and

of the use of nickel-based electrodes, rather than of the expensive noble metal catalysts required in the PAFC. The US$ 27 million (1968 dollars) TARGET ('Team to Advance Research in the Gas Energy Generation') program started in early 1967. It was supported by the 32 gas utilities within the American Gas Association. The objective was to develop a 12.5 kW$_e$ (peak), about 1.0 kW$_e$ (mean) PAFC unit household on-site cogeneration generator [11]. A mass-produced PAFC household appliance with a lifetime of 40 000 operating hours was to be the goal. Its capital cost was to be about US$ 150/kW in 1967 dollars, equal to approximately US$ 635/kW in 1995 dollars [2]. The 1965–1966 engineering systems studies were conducted without a full appreciation of the difficulties in obtaining acceptable PAFC stack materials costs and power densities.

2.2. The TARGET program

The nine-year TARGET program was divided into three three-year phases. In the first, R&D was to be conducted to achieve the required performance, to solve any materials problems, and to perform a preliminary design evaluation. In the second, prototype 12.5 kW units with a net a.c. electrical output approximately equal to 38.5% of the NG feedstock lower heating value (LHV, i.e., with product water in the vapor phase) were to be designed and built. Their waste heat recovery efficiency for cogenerated heat was to be about 40%. The third period (1973–1975) was to be the demonstration and testing phase. By the end of the program, the design for a commercializable real-world product was expected.

Early in Phase 1, it was shown that the cell performance corresponding to the required electrical efficiency (about 0.65 V unit cell voltage) could be obtained at about 100 mA/cm^2 with high platinum loading electrodes (about 10 mg/cm^2 each for the anode and cathode). This would have required about US$ 5000/kW (1995) for the catalyst alone. The cell construction materials and current collectors used in early work were gold-plated tantalum, and were also prohibitively expensive. Alternative catalysts and materials were examined, including possible new acid electrolytes, but nothing was identified beyond the possibilities which were considered in the literature to be thermodynamically stable [12]. The engineering approach used by Bacon and co-workers [7] for the AFC, i.e. pressurize to increase current density, was not considered feasible in small units, since it would require parasitic power, thereby reducing efficiency. Alternatively, operating under pressurize at constant overall efficiency would not increase the net cell power density. Thus, the aim was operation at higher temperatures to increase reaction rates, which was also shown to markedly increase the CO tolerance of the cell anode. The aim was operation

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[2] All costs in the remainder of this text (unless otherwise stated) have been corrected to rounded mid-1995 dollars to allow simple comparisons to be made. The correction factor used is the GNP Implicit Price Deflator, published by the US Department of Commerce, Bureau of Economic Analysis.

beyond 175 °C, up from 150 °C. A search for other possible corrosion-resistant materials was instituted. It was acknowledged that the engineering and materials problems represented by the BOP, i.e. the fuel pretreatment and processing unit, including reformer and shift-converters, cooling systems, water treatment, and d.c. to a.c. conversion) were much less than those in the fuel cell stack itself.

The materials breakthrough came in 1968–1969, when it was realized that the kinetic stability of carbon at the PAFC cathode [11] was far greater than suggested by purely thermodynamic considerations [12]. This allowed a direction for the development of new and less costly PAFC components. Proprietary studies during Phase 2 of the program showed that carbon black and/or graphite composites with certain resins, as well as pure graphite showed good stability at the cathode. At the same time, Teflon®-bonded silicon carbide powder replaced glass fiber and plastics such as Kynol (a phenolic), which were unstable at the higher operating temperature. Inspired from gas-phase high-surface area catalysts, e.g. platinum on non-conducting alumina, platinum could be deposited in relatively low loadings using simple chemical methods on electronically-conducting carbon blacks, which could be made into Teflon®-bonded electrodes. These pointed to the directions in which platinum loadings and per-kW costs could be reduced by improving platinum utilization.

In parallel with the laboratory R&D effort on materials improvements, a conservative 12.5 kW PAFC system was designed and built during Phase 2. This was designated PC11 by P&W [3]. Prototype PC11 units considered of the fuel processor and fuel cell stack assemblies (CSAs) in one box approximately the size of a household furnace, with the d.c. to a.c. inverter in a slightly smaller package, the total weight being 725 kg (1600 lb). Later versions weighed about 500 kg (1100 lb). During Phase 3, 60 PC11 units were successfully field-tested in locations in the USA, Canada, and Japan, starting with a unit in Weatherfield, CT in May 1971 [13]. The materials costs alone could never approach commercialization requirements, and cost for the series was about US$ 100 000/kW (1995), based on the total cost of the early R&D, design, and constructional phase of the program.

The unit cost was much too high, and the PAFC CSA degradation rate and lifetime were too short for the commercial market-place. However, by the mid-1970s, new developments suggested that potentially inexpensive materials existed which could solve both the cost and the lifetime problems. This was reflected later by P&W's patent position on carbon materials [14]. Then proprietary work included new methods of obtaining high-surface area platinum catalysts on carbon, so that electrodes more active than the early ones, but containing only 0.5 mg of platinum per cm² at the cathode

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[3] It followed a series of successive developments after the PC3 AFC. In these the free (but stationary) alkaline electrolyte in the PC3 Bacon-type cell was replaced by electrolyte fixed in a matrix (cf., Mond and Langer, 1889, Ref. [4]). This culminated in the PC8 variants in 1968–69, followed by subsequent PC9 and PC10 designs.

and 0.25 mg/cm² at the anode could be made. In addition, porous graphite could be included in the cell to serve as an electrolyte reservoir, storing sufficient material to compensate for evaporation losses over 40 000 h. This work was first comprehensively reviewed in 1986 [11].

Field-testing with potential customers in the TARGET Program showed the small prototype test units, which were little more than brassboards, could do the job as promised on a day-to-day basis. Customer suggestions and recommendations were used to chart the way to new developments incorporating the R&D material developed in the laboratory. This customer-manufacturer-sponsor interaction was an essential first step on the long road to commercialization of the technology.

3. The 1970s and 1980s

3.1. From TARGET to proposed electric utility systems

If the economic climate of the early 1970s had been the same as that of the 1960s, it would have been reasonable to expect a continuation of the TARGET program on a larger scale, with a much greater commitment of resources by sponsors, potential customers, and the developer. An extension of the PAFC technology to new markets would have been equally expected. The PAFC total energy system had been shown to operate as promised, and means of reducing its materials cost had been identified. With the passage of the 1970 Clean Air Act, dispersed generators with low emissions would be advantageous, and the PC11 was shown to have emissions per MWh which were two order of magnitude lower than those of conventional generators [13]. With a broader market in mind, P&W had such confidence in PAFC technology by 1971 that it felt that it could offer the Edison Electrical Institute (EEI) and ten member utilities a 27 MW system packaged as a series of truck-transportable pallets to allow the generation of electricity anywhere it was needed in a period of rapidly-increasing power demand. This program started in January 1973 [13].

The closing phase of the TARGET program coincided with the economic disruption following the Yom Kippur War in October 1973, when the Organization of Petroleum Exporting Countries (OPEC) used oil supply and cost as a weapon of persuasion. As a result, energy costs soared tenfold, interest rates increased, and economies stagnated. The historical 7.2% per annum annual increase in electricity supply became negative. It had traditionally far exceeded US economic growth. Emphasis was directed to making the economy survive on less energy. The climate was not right for commercialization of new energy-producing devices, however attractive. Weatherization, better insulation, and the encouragement of solar water heating took precedence. The 27 MW Fuel Cell Generator Mark 1 program (FCG-1, a code-name applied by P&W at its successors to their later electric utility systems), to be managed for the electric utilities by the newly-incorporated Electric Power Research Institute (EPRI), was pub-

licly announced in December 1973. Almost immediately, it had to be scaled back in scope.

Originally, developer and utility participation and pricing were for provisional orders for 56 units by nine utilities, a US$ 0.5 million (US$ 1.51 million 1995) down payment being required for each unit, with a US$ 42 million (1995) contribution from P&W (then the Pratt and Whitney Aircraft Division, later the Power Systems Division, of United Technologies Corporation, UTC). Thus, initial development costs were to be shared by the users and the developer on a 67:33 percentage basis. In addition, the users were to pay an additional US$ 21 million (1995) for a demonstrator. Technical developments (but not marketing information) were to be shared between the electric utility and TARGET programs.

A large breadboard system, the PC19 (its designation following that of the 40 kW PC18, see below) was designed and built. It was a 1 MW unit incorporating many innovative features, such as pressurized operation at 3.4 atm absolute (atma), molded 0.3 m^2 bipolar plates made from graphite–polyphenylene sulfide composite and the low-loading carbon-supported platinum electrodes developed during the final phase of the TARGET program. The total R&D and construction cost of this unit represented the equivalent of US$ 60 000/kW (1995). The PC19 generated 698 000 kWh between January and June of 1977, representing an important step in the development of commercial technology, and an inspiration for effort elsewhere. This was particularly the case in Japan, whose developments are described later. A major technical lesson learned from the operation of the PC19 was the fact that the low-cost molded graphite–polyphenylene sulfide bipolar plates lacked the stability for 40 000 h operation at a mean temperature of 190 °C.

While PC19 testing started up in February 1977, the US Department of Energy (DOE) and Electric Power Research Institute (EPRI) decided to go ahead with a request for a development program oriented towards the utility user, who would be assisted by the Federal Government during the early R&D stage. While the prime development candidate could only have been UTC, procurement procedures required a response to a request for proposals, which was issued in February 1977. UTC was selected in July 1977 as the prime contractor, with Consolidate Edison in Manhattan as the host utility on a 0.3 ha (0.75 acre) site at an old thermal power plant at East 15th Street and FDR Drive.

This 4.8 MW (d.c.), 4.5 MW (a.c.) unit was to be operated in late 1978, with termination of demonstration testing in 1979. This did not happen, and a series of unfortunate events (see below) set back the clock on the engineering development and procurement of multi-MW PAFC plants in the USA, and allowed a breathing space for developments elsewhere. By early 1980, it was clear that 4.5 MW operation would be delayed for some time. Enthusiastic utilities required some focus, founding the Fuel Cell Users' Group (FCUG) in April 1980. It had 39 charter members, from all of the US utility classes, including the three major trade associations (the American Public Power Association, the EEI, and the National Rural Electrification Association) as well as off-shore members. The objective of this group of potential users was to determine how to best commercialize the new technology. By 1983, there were 65 utility members. The FCUG sponsored the Fuel Cell Power Plant Applications study in 1982 to determine potential applications for pressurized PAFC units in the 10 MW class within the 1986–2005 timeframe. In the mean time, engineering development and demonstration of multi-MW PAFC units in the USA was on hold [13].

3.2. The UTC 40 kW PC18

One important lesson learned from the TARGET demonstration was the fact that subsystem (BOP) reliability required improvement. In consequence, non-grid-connected units would require back-up systems (for example, a second PC11), which could never be cost-effective. The question of BOP reliability seemed surprising, since the subsystems in question were conventional pumps, motors, sensors, and electronics, all developed for other applications. They tended to have failure rates similar to those in aircraft systems. In contrast, the only purposely-designed and novel part of the system, the d.c. module or CSA, had no mechanical moving parts, showed excellent reliability and a consistent decay rate rather than spontaneous failure. It was originally supposed that small 12.5 kW units could be mass-produced more cheaply than larger units. One lesson learned was that this was not necessarily so. In the PAFC CSA, a large number of small mass-produced cells would not necessarily have a lower per kW cost than a smaller number of larger cells, since economies of scale of manufacture could easily be overridden by the greater labor for assembly. Equally, the chemical part of the unit, as well as the d.c. to a.c. inverter, were as complex in a small unit as in a larger one, and this suggested lower per kW costs in increasing sizes. This was part of the philosophy of offering an electric utility 27 MW unit, which would have been pressurized using the energy from waste heat to obtain higher electrical efficiency.

By 1974 it was felt that an optimum size for small commercial-industrial or neighborhood gas-utility installations was 40 kW. Units were to be capable of hands-off remote-dispatch operation, with grid connection if required, so that surplus electricity could be sold and redundancy assured. The 40 kW proposal followed the PC17B and 17C space-shuttle orbit AFCs of 1974, and so was designated PC18 by UTC. The program involved approximately 30 gas utilities, under the aegis of the new Gas Research Institute (GRI) and the Energy Research and Development Administration, the precursor of US DOE. The concept was the same as that of TARGET, i.e., an Engineering and Development Program (E&DP) followed by a field test at member utilities' sites. The Public Utilities Regulatory Policies Act (PURPA) of 1978 helped progress by encouraging cogeneration using NG and by forcing electric utilities to purchase power from independent producers. Interested gas and combined gas-electric utilities formed the On-Site Fuel Cell Users' Group

(OSFCUG) to implement the plan. While the 40 kW program was being put in place, the electric utility pressurized program continuing from the FGC-1 proposal (see below) was in progress, which maintained confidence in the proposed low-cost electrochemical cell technology with improved performance and lower decay rate. The E&DP was completed by 1982 with the demonstration of 7300 h of power plant operation, with all systems performing to specifications. The cost of the field test, including construction, was estimated at about US$ 64 million (1995) in 1981 for about 50 units to be installed in 20 to 30 US and Japanese locations. US DOE and GRI were to respectively pay 40% and 23% of the cost, each member utility contributing US$ 0.84 million (1995). After the E&DP was completed, six pre-prototypes were constructed and placed in service. Three were in the USA, two in Japan, and one in Mexico City. These units were in 1.8 m×2.75 m×1.5 m (6 ft×9 ft×5 ft) containers weighing 3600 kg (8000 lb), with the inverter in a separate 1.2 m×0.6 m×1.2 m (4 ft×2 ft×4 ft) box. In 1981, NASA-Lewis Research Center, Cleveland, acting as US DOE manager, awarded UTC a contract to produce 45 units for field testing, with a goal of reaching 8000 operating h on each. Typical costs were US$ 17 300/kW (1995), not including installation, which alone could amount to US$ 4250/kW (1995). In all, 49 were manufactured and tested at the sites of 36 host utilities in the USA, at three sites in Japan, and one in Canada. When the program terminated in 1986, its major goals had been attained, with several continuous runs of over 2000 h. A problem in earlier units was fouling of the header of the pressurized parallel-flow water-cooling plates in the CSA by corrosion products even in deoxygenated deionized water, resulting from the use of copper, stainless steel, and mild steel in the system. This required chemical cleaning of the system every 1500–2000 h in most cases. The problem was resolved by using serpentine stainless steel coolers in later units.

Conclusions from the program were that on-site PAFCs were technically commercializable, provided that they were competitive in price. A niche-market competitive cost would be US$ 3060/kW (1995). For widespread cogeneration applications, US$ 1530/kW (1995) was considered to be competitive. Scale-up of units by a similar ratio to that used in going from the PC11 to the PC18 was considered to be the best way to achieve this goal. The resulting atmospheric pressure 200 kW unit would also cover the broadest commercial-industrial on-site market segment. A 1985 report by the OSFCUG [15] identified a feasible US market of 18 00 MW, or 10% of the total commercial electricity market, provided that the cost was less than US$ 1000/kW (1985), i.e. US$ 1360/kW (1995).

3.3. Electric utility demonstrations in the 1980s

The 3.4 atma 4.5 MW Consolidated Edison plant used CSAs based on early technology, without an internal electrolyte reservoir to compensate for evaporative loss over 40 000 operating h. After the lessons learned from the PC19, the 0.34 m^2 bipolar plate consisted of pure graphite with ribs for gas-flow. The estimated construction cost was US$ 16 500/kW (1995), the CSAs costing US$ 4300/kW (1995). Major items were completed in 1978. On-site construction was about one year late, starting in November 1978, and all equipment (except the CSAs, which were in storage) was on-site by mid-1980. An operating license was sought in 1978. The Fire Department refused, classifying the proposed installation as a fuel refinery producing hydrogen in contact with compressed oxidant under potentially dangerous conditions. After arbitration, a license was granted on the condition that the custom-made flat-plate heat exchangers were to be tested with pressurized water, and that only high-flash-point naphtha should be used as fuel. Pressure-testing was done during the winter of 1980–1981. During the short test period, the weather changed and the water froze, bursting several heat exchanges. These were replaced by available spare units, and where none existed, by non-optimized off-the-shelf tube-and-shell units. The Process and Control (PAC) test on the system (still without CSAs) started in November 1981. Many unforeseen difficulties included an unrecorded reformer redesign (a 15 cm height reduction to make it truck-transportable), which rended it inoperable at full load, and a reformer burner which was damaged during start-up. This was because of the Fire Department's requirement for the use of low-volatility naphtha, for which it was not designed.

After necessary repairs, the PAC test resumed in November 1982, and after careful progress, was completed on 17 June 1983. By early 1984, the twenty CSAs were in place. As was by then expected, at least the first group of CSAs manufactured had exceeded their shelf-life, since the original slightly porous graphite bipolar plates had adsorbed enough electrolyte to cause gas cross-over. The second 4.5 MW unit in Goi, Japan (below) was then operating at full power. Attempts to refill the electrolyte failed, and even using three available spare CSAs, a full complement could not be put into place. Rebuilding the old CSAs was not feasible, and new-technology CSAs were estimated to cost US$ 15.7 million (1995), i.e. approximately US$ 3500/kW (1995). No further funding could be spared, and data could be obtained on the second unit operating in Japan. The New York unit, the first and last effort to operate a multi-MW PAFC in the USA, was abandoned and the site was cleared. The PAC test had however shown that the design was operable, and most important, that an official operating permit could be obtained in major urban environment, where other new means of electrical power generation would not be allowed by the authorities.

Japan had been interested in PAFC technology from the start of the PC11 TARGET program, and FC development became a national policy in 1978. The Tokyo Electric Power Company (TEPCO) executed a contract with UTC for a second 4.5 MW unit with the latest 'ribbed-substrate' reservoir-CSA technology in February 1980. The cost was approximately US$ 45 million (1995), i.e. US$ 10 000/kW (1995). The PAC test started at the Goi site in October 1981, and was completed in 12 months (versus 19 months in New York). The CSA cooling systems had the same defect as that

of early PC18s. As much stainless steel piping as possible was substituted for external mild steel, and water purity specifications were tightened. Testing started on 7 April 1983 at 2.0 MW with an unmodified reformer (cf., New York) and with one tube-and-shell heat exchanger substituted to replace unavailable specified equipment. Modifications to bring the unit up to specified output on NG were made during May and June 1983. Operation started in August 1984, full power being reaching in February 1984. The plant operated for 2400 load h (5.43 GWh) until shut-down in December 1985. No performance deterioration was seen, and manpower requirements declined dramatically as experience was gained. Maintenance and modification demands on the prototype were high, and the compact plant in its truck-transportable pallets was difficult to access [13].

Studies sponsored by the FCUG in 1982 indicated that an electric utility PAFC with excellent availability characteristics, an LHV efficiency of at least 45.9% (preferably 47.3%) and an installed cost of US$ 1600/kW (1995) would be competitive with other clean generators (gas turbine combined cycles, GTCCs) [13]. The pressurized PAFC was very non-intrusive from the environmental and neighborliness viewpoint, and was considered to be an ideal dispersed generator at the substation level for urban sites. Many of these could not be supplied by new transmission capacity, and new regulations prevented the installation of combustion machinery. The pressurized PAFC was considered to be desirable for both new sites and for repowering of old urban facilities. Compared with that of large conventional plants, its introductory capital cost could be partially offset by accounting credits for transmission lines, for improved grid operation, and for the short lead-times to operation for small-scale dispersed equipment. The moment seemed right for the sale of 11 MW units using larger stacks, which would have a higher efficiency by operating at higher pressure, which would allow the same fuel processor volume as that of the 4.5 MW units. The higher operating pressure would also reduce the cost of piping.

A preliminary version of a 'definitive' EPRI-sponsored electric utility power plant design (still called FCG-1) was unveiled by UTC in 1983. It was to use essentially the same fuel processing system as the 4.5 MW units, operating at 8.2 atma instead of 3.5 atma. Its LHV efficiency would be 45.6% instead of the 40.7% figure for the 4.5 MW demonstrators, which would be achieved by operation at 0.73 V and 0.216 A/cm^2 instead of 0.65 V and 0.25 A/cm^2. With the same gas volume throughput as the 4.5 MW units, output would increase to 12 MW, and the unit was rated at 11 MW. The proposed cell active area was increased by a factor of 2.7 to 0.93 m^2. In 1985, UTC announced the formation of International Fuel Cells (IFC), a joint venture with Toshiba (the site contractor at Goi) as a minority partner. The purpose of the company was to commercialize the PAFC. In the same year, a brochure announced a modified version of the FCG-1 intended as the definitive commercial electric utility offering, designated PC23. The first three prototypes would be

offered at US$ 3600/kW (1986), i.e. US$ 4800/kW (1995). The next 20 units would be half that cost. Only complete turnkey plants were offered.

By the end of 1988, it was expected that five units would be ordered by US utilities [13]. For a number of reasons, all of the orders failed to materialize. Between 1985 and 1988, internal studies by utilities found that the proposed 11 MW design was either too large for their sites, or too small, or had the wrong footprint. A reason cited at another site was the unavailability of a suitable inexpensive test fuel supply (refinery off-gas). For urban installations, the cost of space was a problem. For example, Consolidated Edison in New York City would have preferred a 100 MW, multi-storey installation. Similarly, the City of Palo Alto found that the cost of urban sites for a unit would be too great. A major contributor to the problem was the economic turndown during the late 1980s.

No US utility customers were found for 11 MW units at the introductory price. Utilities considered the concept to be attractive, but only if its capital cost was truly competitive, i.e. about US$ 960–1070/kW (1995), plus any credits for dispersed operation. Utilities expressed concern for the financial unknowns involved in operating new and unfamiliar technology, which included the effective cost of CSA replacement. The argument that CSA technology would be expected to greatly advance over a five-year replacement period was not persuasive, even though CSA performance had always shown progressive improvements with time.

In consequence, IFC virtually abandoned the development of large pressurized PAFC systems after 1990. The US DOE program to improve pressurized PAFC technology terminated in 1992 with demonstration of current densities increased by 20% at rated cell voltage to 243 mA/cm^2 [16,17]. Demonstrations were up to short stack level, and included components of the proprietary 'Configuration B' type indicated (although not described) in earlier work [11]. Results obtained showed a 40 mV improvement at 216 mA/cm^2 over average results reported in 1985–1986, with a lower IR drop, allowing operation at up to 370 mA/cm^2 at 0.73 V in a short stack. Data in subscale cells were about 50 mV higher. Part of this performance increase was due to the use of improved alloy catalysts in a higher equivalent loading [17], following work reported in 1986 at a 0.9 mg/cm^2 cathode loading, which had allowed a performance of 0.73 V at 1000 h at double the standard operating current density, i.e., at 432 mA/cm^2 [11]. The logarithmic decay rates made it clear that these cells would give 40 000 h lifetime within the performance specifications, even under pressurized conditions where corrosion or rearrangement of cathode catalysts and supports were more significant [11].

4. IFC electric utility demonstrations in the 1990s

While IFC had said that it would offer only turnkey 11 MW plants, TEPCO succeeded in obtaining 11 MW CSAs for a prototype demonstrator on the old site at Goi in arrange-

ments made in 1988. It was based on the PC23 system, using IFC CSA technology and system design, Toshiba site engineering and Japanese BOP. The system used 16 CSAs. The project cost was estimated to be US$ 150 million (1988) at the then conventional trading exchange rate, i.e. about US$ 187 million (1995). Of this, fabrication was approximately 50% or US$ 8500/kW (1995). Construction started in January 1989, and the plant was completed in 13 months. The process and control (PAC) test was conducted without CSAs from June to November of 1990 in only 82 days (2.7 months), instead of the planned 128 days. This was a remarkable advance on the 12-month PAC test time for the 1983–1985 Goi 4.5 MW unit. The plant reached rated power on 26 April 1991. The LHV efficiency was 48.4% (gross AC, 46.4% net) at 11 MW, 45.5% at 7 MW, and 38.8% at 4 MW. These figures were about 0.7% greater than specifications. In July 1991, a continuous run of 875 h at an average load of 70% was conducted. During this period, the voltages of all 16 CSAs were very uniform. By the end of August 1991, 10 263 MWh had been generated. At the end of August 1992, the system had operated for 4041 h (23 435 MWh), with a longest continuous run of 1173 h, and with 16 start-up cycles. Waste heat was used to air-condition the control building in a cogeneration demonstration [18]. By March 1994, the plant had operated for 9272 h. In March 1995, the figure was 12 960 h [19], and it attained 16 000 h in September 1995.

Specific problems which developed in 1991 included a vibration-induced breakdown of the recycle blower impeller, which was replaced with a heavier damped part, a GTO failure in the inverter due to negative electric bias at low load, which required a higher bias voltage, a controller circuit broad failure, which required enhanced dust and moisture protection, and erosion-corrosion-induced water leakage in heat-exchanger bypass piping, which was replaced by stainless steel. A major failure was corrosion of graphite in six of the CSAs, which was shown by an insufficient voltage rise during standby-to-transient operation. This caused leakage of the external purge gas into the reactant stream. The reason was the use of reformer burner exit gas as the purge, which was intended to save the cost of using nitrogen. This gas contains small amounts of oxygen, CO_2, and large amounts of water vapor, and was capable of causing graphite corrosion under pressurized PAFC cathode operating conditions, where graphite is locally operating at its corrosion limit. As a result, reformer off-gas was replaced by nitrogen as the purge gas, and the system operated at 67% of design capacity with six CSAs disconnected. Methods for reducing nitrogen requirements were explored during subsequent testing.

Outages have been rare apart from the above problems. Inverter and reformer operation was satisfactory, and operation has shown how improvements might be incorporated (Yokata et al., 1992). The operating CSAs showed much less than the specified decay rate for the first 500 h, so that the total voltage and efficiency loss over an operating period of 40 000 h extrapolates to 7%, rather than 10%, i.e. the effective CSA life to 41.7% net LHV efficiency may be

100 000 h, rather than the 40 000 h anticipated, provided that sufficient electrolyte inventory is present. The exhaust gas contained between 1–3 ppmv NO_2 (7% oxygen, dry basis), i.e. 1.8–5.3 g/MWh, an extremely low value compared with the best gas turbines. In spite of the operational accident which left it with only 12 out of 18 CSAs operable, it has performed extremely well and will continue to be operated.

In Europe, a 1 MW PAFC using purchased IFC PC23-technology CSAs and Kinetics Technology International (KTI) BOP was operating at full power in Milan in 1994.

5. The IFC 200 kW PC25™ on-site system

5.1. Progress to date

The 200 kW on-site unit proposed to gas utilities by IFC in 1986 went through a number of successive changes with time. As has been already remarked, US DOE considered PAFC systems to be ready for commercialization in the late 1980s, and its support on cell technology terminated in 1992. GRI's attitude was similar. The system was first proposed with a 0.34 m^2 CSA using the new 'Configuration B' low-resistance ribbed-substrate technology operating at 216 mA/cm^2. Later, this was changed to 0.47 m^2 and 250 mA/cm^2 to reduce the overall CSA height. The higher current density was permitted by performance improvement [16,17]. Since the decay environment at 0.65 V under atmospheric pressure conditions is much less aggressive than at 0.73 V and 8.2 atma pressure, there is no question that the lifetime performance of cell components would be as specified. The system was designated PC25™ [4] by IFC. Since the air-cooled PAFC developed by Westinghouse [11,13] was abandoned due to lack of customer interest in 1992 [5], IFC is the only important remaining US PAFC system developer.

Four pre-prototype units, designated PCX, were constructed and sold to Japan, which made the development of the PC25 possible. They were tested by TEPCO (PCX-1 and -2) [20,21], Osaka Gas (PC25YX-1) [22], and Nippon Petroleum Refining Co. (PC25YX-2N) [23]. The two TEPCO units performed for 5210 h (876 MWh) and 3780 h (409 MWh), with 1393 and 409 maximum continuous h, respectively, by August 1990. The PCX-1 unit at the Shin Tokyo thermal power plant started up in October 1988 and was terminated in 1990. It required CSA replacement during operation. The PCX-2 was installed in a building in Shiba-

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[4] PC25™ is an IFC-ONSI registered trade mark for the 200 kW pre-packaged on-site PAFC. The 'TM' superscript is not used in the subsequent text.

[5] The Westinghouse air-cooled stack technology, originally licensed from Energy Research Corporation (ERC), Danbury, CT, has been retained by a new company, Fuel Cell Corporation of America, who plans a 400 kW module. Before abandoning its program in the late 1980s, Engelhard Industries licensed its PAFC technology to Fuji Electric. ERC is concentrating on the development of MCFC technology. It licensed air-cooled PAFC technology to the Sanyo Electric Company (Sanyo Denki) in the early 1980s.

ura, Tokyo in March 1989. In August 1990 it was transferred to the Shiba-ura District Heating and Cooling Plant. By November 1991, it had operated for a total of 11 141 h (1059 MWh), with a maximum continuous run of 3245 h, a world record at that time. Net AC efficiency was (maximum) 38.5% at 150 kW output, and fell to 33.5% at 200 kW (without heat recovery) and to only 31.5% (with heat recovery). Overall electrical and heating efficiency was between 67 and 70.5%. NO_2 emissions were given as 3 ppmv (7% oxygen, dry basis) in 1990, and a maximum of 13 ppmv in 1992, considerably less than the 25 ppmv target. Cell voltage showed a drop of 6.5% per 1000 h, which seemed to be related to system shutdowns. Future requirements included better stability, lower cost, and lower parasitic power requirements at part load. At 14 500 h, the CSA was replaced by a new one made by Toshiba. By September 1995, the BOP had accumulated 35 000 h, a world record, and the Toshiba CSA had exceeded 20 000 operating h. The Osaka Gas PC25YX-1 unit started up in April 1989, and operated in the Umeda Center Office building for 3800 h by July 1990. Its NO_2 emission were at the limit of detection, 2 ppmv. The user stated that power section durability required improvement. The PC25YX-2N at the Nippon Refining Company was a 130 kW (nominal) unit modified to include enhanced desulfurization for operation on low-sulfur naphtha (boiling range 28–72 °C, 0.1–0.3 wt. ppm sulfur). It started up in March 1990, and had operated for 4808 h up to the end of 1991 at an average load of 106 kW. A system was to eventually operate on No. 1 kerosene (boiling range 190–258 °C, 10–100 wt. ppm sulfur) using a Haldor–Topsøe kerosene reformer.

The performance of the early 200 kW PCXs has been greatly improved in the later PC25 units, both from the viewpoint of emissions, efficiency, and decay rate. The 200 kW PC25 on-site cogeneration unit operating at 40% electrical efficiency (about 90% total LHV efficiency) manufactured by the ONSI joint venture (1990, IFC and Toshiba [6]) was the only fuel cell system close to true commercial application in 1994.

Commercialization prospects for the PC25 appeared to be good in 1994–1995. When it was in the planning stage, it was hoped that 100 of the first run would be sold, after investment in plant capable of producing 10 MW (50 units) per year starting in 1990, with expected expansion to 40 MW per year (200 units). The early market assessment proved optimistic. The first pre-production run of the OSNI 200 kW unit (the PC25A) finally involved 56 demonstration units, 22 of which are in Japan, 1 in Korea, 10 in Europe, 13 in California, and 10 in the rest of North America. Unit cost was about US$ 3450/kW (1995) for early units, which rose to approximately US$ 4800/kW (1995), including training services,

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[6] The ONSI joint venture is intended to produce on-site cogeneration PAFC plants up to 1 MW$_e$. Under the agreement, Toshiba may not export its own units before 1998. Toshiba and IFC do not compete in Japan, but may compete elsewhere.

as real costs assembly labor cost became more accurately determined. True production costs were said to be higher than the selling price.

Total cumulative operating hours for the PC25A were 140 000 h in September 1993, and 215 620 h at the end of 1993, with 38 units then operational, with a worldwide overall average availability of 93.5%, and a US availability of 95.4%. By May 1994, they had accumulated over 300 000 operating h. By 31 December 1994, 51 units had been installed, with 501 434 h accumulated, with a mean availability of 95.1%. The Sydkraft, Sweden unit, delivered in June 1992, had accumulated almost 13 000 operating h by March 1994. Its performance and degradation were within the expected norms from stack bench testing. It had the distinction of requiring only 7 days from delivery to a prepared concrete pad to power generation. The Korea Gas unit, delivered in September 1993, was also operating 7 days after being placed on its prepared concrete pad. At the end of 1993, the first Southern California Gas PC23A (No. 9004) had accumulated 11 031 h, at 92.3% overall availability. By 31 December 1994, it had accumulated 18 590 h. Number 9001, the oldest of 8 Osaka Gas units replacing the PC25YX-1 in the Umeda Center in Osaka, started up in August 1992 and was at 10 716 h at the end of 1993, with 95.4% availability, and a then-record 5476 h of continuous operation. It had reached 14 692 h by August 1994 [24]. The highest availability was then 99.3% for the unit at Pittsburgh International Airport (7277 h at the end of 1993). The Irvine, CA, SoCal Gas unit (No. 9005) had 10 554 h at the end of 1993 (96.4% availability), and the unit at Brooklyn Union, NY (No. 9025) had 9428 h at 94.9% availability. The SoCal Gas units installed in September 1994 had completely 3700 h by the end of 1994, in a continuous run representing 100% availability. On 28 August 1995, one unit (No. 9041) had a continuous run of 8451 h from 6 September 1994 to 24 August 1995, and the other (No. 9041) had continuously operated from 7 September 1994 (8509 h at 100% availability). By 21 August 1995, 9 units had exceeded 20 000 operating h (SoCal Gas No. 9004, 24 121 h; No. 9005, 22 405 h; Osaka Gas No. 9001, 21 752 h; IVO No. 9021, 21 713 h; Sydkraft No. 9006, 21 481 h; Brooklyn Union Gas No. 9025, 21 237 h; Thyssengas No. 9012, 21 064 h; Equitable Gas No. 9023, 20 459 h; and Ruhrgas No. 9011, 20 067 h). Three others had exceeded 19 000 h, and a total of 21 had exceeded 16 000 operating h. A total of 19 units had had continuous runs exceeding 6 months.

5.2. Progress towards a commercial model

By 1994–1995, the PC25 had gone through four stages of design evolution, from the PCX pre-prototypes to the PC25A, B, and C models. In addition to the 56 PC25As, 18 relatively similar PC25Bs were being installed on military bases during 1994–1995. In July 1994, it was announced that the PC25C would be on offer at US$ 3000/kW (1995), a reduction of about US$ 2000/kW compared with the previous version, provided as always that a sufficient number of launch custom-

ers were available. Production of the PC25C was under way in mid-1995. The medium-term aim was to reduce the cost of commercial units (the PC25D) to US$ 1500–1600/kW (1995) in 1998. The first commercial cogeneration niche-markets would become available at a selling price of approximately US$ 2650/kW$_c$ (1995). IFC had identified 100 000 buildings which would meet their target criteria for PC25 installation in the USA for which a capital cost of US$ 1600/kW$_c$ (1995) or greater would be economical. Half of these building would have economical installations at US$ 1900/kW (1995). The goal for installation cost was an additional US$ 400/kW (1995).

For viable production, the initial output of PC25C units should total 10 MW (50 units) per year for three years, with increasing production thereafter. Inevitably, a major investment or subsidy, estimated by IFC at approximately US$ 75 million (1995), and by Arthur D. Little, Inc. at twice this amount, would be necessary to achieve a production rate of 200 units per year, and so reduce the selling price to commercial levels following the normal learning curve process.

IFC had made a major effort to reduce the cost, weight and volume of components, which included those of heat exchangers, the CSA, the inverter, and the reformer. The PC25C would weigh 18 200 kg (40 000 lb), compared with 27 300 kg (60 000 lb) for the PC25A, and 36 000 kg (80 000 lb) for the first PCX prototypes. Its dimensions would be similarly reduced. The PCXs were 3.5 m(height) × 3.5 m × 11.3 m (11 ft5 × 10 ft × 37 ft), whereas the PC25A was 3.5 m × 3.0 m × 7.3 m (11.5 ft × 10 ft × 24 ft), and the PC25C will be 3.0 m × 3.0 m × 5.5 m (10 ft × 10 ft × 18 ft). Current density has been progressively increased from 216 mA/cm^2 as performance improved. It is now some 30 mV better than 1985 single cell data corresponding to 0.62 V [11] at 325 mA/cm^2, and the shortened 231 cell PC25C CSA (originally 320 cells) will operate at 300 mA/cm^2, reducing CSA height, therefore its weight, volume and cost. Since most of the final cost is in assembly, the effect of the reduced parts count on cost is important. In a new development, production teams assembling each unit continually study methods of simplifying assembly and reducing assembly time and cost [25].

Thus, IFC had already made considerable progress in fuel cell system design innovation to reduce cost [26]. Mechanical parts have been reduced by 25% in the PC25C, and cooling improvements increase its reliability and time-to-overhaul. The component count in the fuel control system has been reduced by 60%, giving a 70% reduction in cost. Improved fabrication methods have resulted in a CSA cost per unit area which is 40% less. Heat exchanger weight is down by about 70% by the use of improved flat plate technology to replace tube and shell structures. Improvements in the inverter (conducted with Toshiba) have allowed a 5 ton weight reduction and an approximate 70% volume reduction. It now uses Insulated Gate Bipolar Transistors (IGBTs) to eliminated many inductors and transformers [25]. Toshiba envisages the use of small water-cooled inverter in the future [27]. Future improvements to the reformer (with Toshiba)

and to other heat-exchange structures are envisaged. Parts are being integrated, e.g. in a combined valve, gauge, and pump assembly, rather than using separate vendor-supplied items. The weight of the US$ 1500/kW 1998 version, the PC25D, might be reduced to 14 000 kg (30 000 lb), with a volume 25% less. A 1.25 MW unit with 6 PC25C (or D) CSAs, with 4 single modules for fuel processing; air supply, control, power distribution, controls, and water treatment; power conditioning, and cooling was in the planning stage in late 1994 [28].

5.3. PC25A user reactions

The negligible emissions of the PC25A as measured in California (0.45 ppmv NO$_2$, 2 ppmv CO, 4 ppmv total hydrocarbons at 15% oxygen, dry basis, compared with California combustion engine standards of 36 ppmv for NO$_2$, 2000 ppmv for CO, and 250 ppmv for reactive organic gases, ROG), resulted in its receiving a blanket exemption from the South Coast Air Quality Management District. The hydrocarbon emissions were mostly methane, which is not an ozone-forming pollutant, with negligible higher hydrocarbons. These PC25A emissions (from the lean reformer burner) are equivalent to 2.4 g/MWh for NO$_2$ and 4.5 g/MWh for CO, which are orders of magnitude below those for other generating equipment. Measurements in Germany indicate about 1 ppmv NO$_2$ (5% oxygen, dry basis) at full load, and 13 ppmv CO, corresponding to 2.0 g/MWh for NO$_2$ and 26 g/MWh for CO. German standard for gas engines were 224 ppmv for NO$_2$, and 250 ppmv for CO, measured under the same conditions [29]. Similar results for NO$_2$ emissions are announced by the new European Fuel Cell Users' Group (EFCUG), established in 1991 [30]. While the ppmv CO level depends on reformer burner adjustment, it is always at least one order of magnitude better than that for other equipment, and close to two orders of magnitude better than figures for internal combustion engines with catalytic converters.

North American operating experience on 16 PC25As was summarized by representatives of 13 utility members of the North American Fuel Cell Owners Group (NAFCOG) at the 1994 International Fuel Cell Seminar [31]. Site permits were easily obtained everywhere. Installation cost depended on thermal recovery requirements, which in some cases were not justified. NAFCOG members stressed the excellent user manual, the control system which could be monitored remotely by members and ONSI via modem, instant technical backup by telephone during working hours and within 30 min at other times, the overnight service for parts delivery, and the low performance decay rate. These have resulted in an effective availability of 95.5% including scheduled outages in a 10-unit fleet with parts back-up and service personnel. There were 50 forced outages, 12 of which were in ventilation fans and process air controls, and 14 in the electric systems. In addition, 26 inadvertent operations of shut-down buttons occurred, 11 of which were due to operator inexperience. The mean time to forced outage was 2500 h. Since about half of

the reasons for outage have been designed out of the 1995 PC25C, a future rate mean time to outage of 5430 h is projected. The improvement is shown by the mean time to outage during the fleet history. It was about 1000 h during the first half of 1992, 1820 h in the corresponding period in 1993, 2320 h in the same period in 1994, and 3290 h from 1 June 1994 to 14 August 1994. This compares with the North American Electric Reliability Council Generating Unit statistics (1988–1992) of about 500 h for fossil plants, 400 h for geothermal plants, and 1400 h for nuclear plants. Similarly, the January 1990–September 1992 Gas Research Institute statistics for cogeneration plants show mean time to forced outage of 500 h or less for reciprocating engines (60 to 800 + kW) and gas turbines from 1–25 MW, with a figure 1500 h for units over 25 MW.

The Tokyo Gas Company had 7 PC25As installed between July 1992 and January 1994, 2 of which had attained 10 500–11 000 h by August 1994. One unit has been converted by Toshiba to produce cogenerated steam, rather than 60 or 90 °C hot water. The degradation rates on 3 PC25As which had approximately 11 000, 9900, and 8650 operating h by August 1994 have been compared. All showed lower degradation than that predicted from an estimate of 10% voltage decay over 40 000 h, following a semilogarithmic relationship as a function of time. In the first two cases, some early decay occurred, which was followed by relative stability. Both CSAs were operating about 20 mV above the estimated decay curve. The third unit at Sodegaura Works (8653 h in August 1994, installed in June 1993) improved with time over 5000 h, and was substantially (about 55 mV) above the decay curve at 8000 h [32]. It appears that performance decay is less apparent with newer PC25A units, since the three represent mid-1992, late-1992, and mid-1993 technologies respectively.

6. Fuel cell commercialization

6.1. The competition

When the pressurized PAFC was being developed in the 1970s and early 1980s, simple cycle gas turbines were available at low cost. Manufacturer's quotes for peaking machinery were typically about US$ 270/kW (1995) for 10 MW to 100 MW units with 25% LHV efficiency. Because of their low efficiency and the then-high cost of fuel, peaking turbines were not considered to be competitive with a pressurized PAFC acting as an intermediate-load machine. In 1985, the NG combined cycle turbine (GTCC) was only beginning to be introduced into electric utility generation mix. NG was regarded as a scarce and relatively costly fuel, and was expected to become more costly in the future. In 1982, gas prices were about US$ 6.40/MMBTU (1995) (US$ 6.10/

GJ, HHV [7]), and they were expected to rise by 7% per annum, close to the inflation rate at the time. Utilities were therefore reluctant to invest in baseload NG machinery. However, deregulation caused prices to fall rapidly to US$ 2.00/MMBTU (1995) in 1987 and US$ 1.60/MMBTU (spot) in December 1994. Inflation rates were also less than half of those originally predicted. Since the passage of the Clean Air Reauthorization Act in 1990, NG has not only become cheaper and more available, but has also become desirable from the viewpoint of emissions. In particular, NG plants emit negligible SO_2, and fuel costs are less than those for coal plants when the cost of flue gas clean-up is taken into account. Because of the low cost of NG, a higher LHV efficiency for generating equipment may be less important than in 1985, but it is still valuable. The overriding factors in competitiveness are plant capital cost, reliability, availability, and maintenance cost.

Since 1985, the GTCC has been a moving target from the viewpoint of efficiency, emissions, and reliability. There has been little change in its installed cost in real terms. By 1988, GTCCs were available with an LHV efficiency of 50% and low NO_2 emissions (20–40 ppmv at 15% oxygen, dry basis, or 300–600 g/MWh of NO_2). By 1991–1994, they were available with 9 ppmv NO_2 emissions (at 15% oxygen, dry basis) at LHV efficiencies up to 58.5% in a combined cycle (e.g. as a 160 MW unit from Asea–Brown–Boveri, ABB). The combined cycle machines cost about US$ 800–900/kW (1995), about 50% of the cost of a clean coal plant, and less than the cost of a NG steam plant. The 9 ppmv NO_2 emission figure (at 58.5% efficiency) corresponds to only 115 g/MWh, only 6% of that of a coal plant. With emissions credits, GTCC capacity is therefore extremely attractive. Turbine machinery also became more reliable, with better than 1000 h between forced outages. Typically, detailed combustor inspection was required at 8000 fired h, hot section maintenance at 24 000 fired h, and major overhaul every 48 000 fired h. Experience with the PC25A shows that future models will more than compete with GTCCs in emissions (2.4 g/MWh for NO_2), and in reliability ($\geq$ 5000 h between outages and $\geq$ 99% availability, not counting planned outages). Inspection and maintenance may be at 8000 h intervals, involving a few man-hours of labor. Stack replacement may be required at 40 000 h, but the addition of an acid replishment system may extend CSA life to up to 100 000 h. Since the FC units are only 0.1% of the size of a large GTCC, planned or forced outage has little impact on overall generating capacity.

These considerations are powerful, but not overriding. NO_2 emissions of 115 g/MWh are better than the law requires, and 'negligible' emissions will not necessarily sell a new technology unless the law is changed. Maintenance requirements of the GTCC and the PAFC will be comparable. A

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[7] Fuel costs are quoted as higher heating value (HHV, liquid water product), since this is easy to measure and control and is how fuel is sold. For NG, HHV is approximately 1.11 LHV.

55% (LHV) efficient GTCC has an effective efficiency at the substation level of perhaps 52%. Based on the fuel cost of delivered power, a dispersed 200 kW 40% (LHV) efficient PAFC will cost US$ 28/kW per annum more to operate than the GTCC, assuming NG costs of US$ 2.50/MMBTU (US$ 2.40/GJ, HHV) and a capacity factor of 65%. This is equivalent to a capital cost debit of at least US$ 140/kW.

A gas-electric utility must therefore have compelling reasons to select the dispersed PAFC over the state-of-the-art GTCC at US$ 850/kW (1995). However, the dispersed sub-MW PAFC does have financial advantages. Most of these are site-specific, so it is not possible to generalize. However, the dispersed d.c.-a.c. electronic interface stabilizes the grid, giving power stability credits. Dispersed generation also improves spinning reserve and peaking capacity. Transmission and distribution credits are certainly site specific, as are electricity loss savings (which were already been accounted for in the above illustration), and environmental credits. Finally, the cogeneration heat has value at least equal to that of the gas it would replace, i.e. about US$ 57/kW$_c$ per year. The latter alone more than compensates for the higher electricity generating cost, and gives a net capital cost credit of US$ 145/kW$_c$. According to a Los Angeles Department of Water and Power distributed-generation study, the site-specific electrical credits may lie between US$ 115–320/kW per year in levelized 1995 dollars at 65% capacity factor, depending on the California site examined [33]. At almost all sites, a capital cost US$ 1500/kW$_c$ (1991) for a reliable on-site cogeneration PAFC should be acceptable. At a small number of niche-market sites, US$ 2500/kW$_c$ may apply. Using the same methodology, a pressurized 45.6% (LHV) efficient PAFC at the substation level will cost US$ 25/kW per year more to operate than a central 58.5% (LHV) GTCC, which may be greatly offset by site-dependent electrical credits. Thus, at all sites, a non-cogeneration dispersed electric utility PAFC might be competitive with a central GTCC at a capital cost of US$ 1400/kW, and a 50% LHV MCFC should compete at US$ 1425/kW. At four California sites, the latter would compete at US$ 1500/kW (1991) or US$ 1650/kW (1995) [33]. When it is used with landfill gas as fuel, the PAFC (or other fuel cell technologies) would also benefit from a 95 ¢/MMBTU (90 ¢/GJ) tax credit. An IFC–EPA program on the use of landfill gas in the PC25 has been summarized [34].

Because of the risks inherent in any new technology and the fact that buyer suspicion is inevitable, innovative marketing approaches are essential. Indeed, they were used in the TARGET program, when gas companies, not energy users, would own the fuel cell equipment. Leasing of equipment to users is one possible approach, but a better solution may be the sale of power by intermediaries, so that customers who are sophisticated in their own domain (e.g. hospitals and other electronic-intensive clients requiring high-quality uninterrupted power, cf. Europe, below) do not have to buy their own power equipment. An excellent example of this approach is the May 1994 agreement between ONSI and Enron Emerg-

ing Technologies, Inc. (EETI), a subsidiary of the major pipeline company Enron Corporation. EETI was formed in January 1994, and signed an agreement to market energy product services (delivered electricity and heat) using the PC25. Under the agreement, the customer would not involve the risk of owning or operating the unit.

6.2. Commercialization in Europe

The situation in Europe was somewhat different from that in the USA. National nuclear embargoes or program reductions (except in France), the increasing availability of natural gas, emissions regulations (e.g. for acid rain), and the small geographic extent of national grids make GTCC plants with cogeneration attractive. Distributed cogeneration (combined heat and power, CHP) represented an advantageous way to reduce CO_2 greenhouse gas emissions, which must be lowered by 25% in the residential sector by 2010. The Netherlands had 4 GW$_c$ of cogeneration (combined heat and power, CHP) capacity in the 25 MW$_c$ to 400 MW$_c$ range in 1994 in an integrated grid serving 15 million people in an area of 42 000 km^2 (about 25% larger than Connecticut, Massachusetts, and Rhode Island combined, with 45% greater population). The capital cost of these low-noise (45 dB at 50 m) GTCC CHP 50% LHV, efficiency units was US$ 770–870/kW$_c$ (1995), and the market was 200 MWe per year. Based on 1985 projections (see below) the eventual capital cost of a pressurized PAFC was estimated at US$ 1250/kW$_c$ (1995). However, the GTCCs are in the 25 MW class or greater, representing a major capital investment, which could be deferred if FC systems were available at attractive costs. European countries differ in grid integration. A technology which might be appropriate in former Eastern Germany, or Southern Britain, or in parts of Italy would not necessarily be appropriate in The Netherlands. Gas-fired capacity in The Netherlands and the requirements for fuel cell system to compete were reviewed in 1991 [35].

Whether the on-site PAFC can compete in Europe will largely depend on its capital cost, and on the evolution of small gas engines for CHP applications. A typical CHP utilization (e.g. in Germany) was 4000–4500 h per year. If renewable fuel (e.g. landfill gas or biogas) was used, the electricity produced had a 'guaranteed buy-back' of 16.8 Pf/ kWh (10.5 ¢/kWh) in 1994. In mid-1994, The Netherlands and Germany had gas engine CHP units in the 100 kW$_c$ to the > 1 MW$_c$ range. The majority (85–90%) of Germany's total CHP capacity of 700 MW$_c$ was in the several hundred kW$_c$ range. About 100 MWe of small diesel capacity already existed in Southern England. Small-scale CHP may therefore represent a large market. Compared with conventional equipment, the PAFC might offer a 25–40% reduction in fuel costs, a reduction in greenhouse gas emissions, and a 99% reduction in toxic emissions. The PAFC can be designed to produce 170 °C steam for double-acting absorption chillers in the commercial sector. This is the plan for CHP in Japan, where Toshiba is modifying PC25s to produce steam rather than hot

water, see Ref. [27]). Other Japanese developers are also developing steam-producing PAFC equipment. The PAFC could be used in a cheap, simplified form where excess industrial hydrogen was available, e.g. along the German and Rotterdam to South Belgian hydrogen pipeline systems, and in Italy, where by law electricity from chemical byproducts (e.g. hydrogen) could be sold at premium prices. Some industries might lease fuel cells (e.g. the chlor–alkali industry), whereas gas companies may use their own equipment to sell electricity (and cogenerated heat) to hospitals, who do not want the responsibility of owning and operating their own equipment (cf. the Enron–ONSI agreement in the USA). Hospitals and other major users of electronic equipment require high-quality, non-interruptible power which could be provided by dispersed CHP PAFCs rather than by rechargeable batteries. As in the USA, concerns about electromagnetic fields, esthetics, and costs mean that new transmission line capacity will be limited, favoring dispersed generation. Pollution concerns in historic city centers and in Eastern Europe, together with resource pressures favor energy efficiency and cogeneration, preferably via FCs if capital costs are acceptable.

The on-site PAFC would have many advantages, including low noise and pollution levels. However, noise must still be reduced for use in residential areas, particularly in Germany, where the upper limit for night-time noise is 35 dBA. This would require silencing of the cooling system for air-cooled FC units. Regulations on system use also require overhauling, since they are left over from those for other conventional equipment (cf. the New York 4.5 MW unit treated as a 'refinery'). An example was the requirement for expert safety reports for each site (even when FC units are moved) and the requirement for analysis of the product water [29]. Inevitably, the major issue would be cost of power. Small diesels, which require expensive sound muffling, had LHV efficiencies of 36–39%, compared with about 40% for the PC25A. Their capital costs were about DM 3000/kW$_e$ (about US$ 2200/kW$_e$) in the 40–50 kW$_e$ class. In the 200–500 kW$_e$ and > 1 MW$_e$ classes, installed costs were about DM 2000/kW$_e$ (US$ 1450/kW$_e$), and DM 1500–2000/kW$_e$ (US$ 1080–1450/kW$_e$), respectively [8]. The operational lifetimes of these units was 40 000 h. This is similar to that expected for PAFC CSAs, but it is much less than the expected 30 year life of PAFC BOP. The smallest CHP units (in the 6–7 kW$_e$ class for domestic use) cost DM 3000–4000/kW$_e$ (US$ 1875–2500/kW$_e$). In many applications, US$ 2500/kW$_e$ (1995) for PAFC systems may be acceptable in Europe. However, to cover the broadest market, capital costs should be in the US$ 1000–1500/kW$_e$ (1995) range. To compete with diesels in Sweden, a capital cost of US$ 1550–1650/kW$_e$ (1995) is recommended [30]. In general, operating experience with dispersed fuel cell systems in Europe was satisfactory, and improvements were required to BOP, rather than to the CSAs.

[8] Costs in this Section are approximate, since the trade exchange rate has fluctuated widely during 1995.

Footprints required reduction without compromising maintainability, and control systems must be adapted to individual customer requirements. Finally, the availability of heat for absorption chillers was again emphasized [36].

CLC srl, an Ansaldo srl (Italy) subsidiary, obtained a license from IFC–ONSI in 1992 to manufacture and sell the PC25 and other PAFC units up to 1 MW in Europe. The European model will comply with differing European standards and regulations. The plan was to first import complete PC25s, then European-manufactured BOP would be used with IFC–ONSI CSAs. By 1994, European graphite vendors had been identified, and stack parts were being manufactured by CLC–Ansaldo. Already, it was offering a 50% efficient hydrogen-powered unit at about US$ 2050/kW$_e$ (1995).

Since 1992, Siemens has studied the development of cogeneration turn-key PAFC units in the 1–2 MW$_e$ class in a joint venture with potential users, using technical input under an information exchange agreement with the Fuji Electric Company. Stacks would be supplied by vendors, for example, IFC, Ansaldo srl, Fuji Electric, or the Mitsubishi Electric Company (MELCO), with Siemens supplying BOP. Partners in a joint feasibility study on plant design, control systems, and licensing arrangements are GEW–Köln (17%), Ruhrgas A.G. (8%), Thyssengas GmbH (8%), and Siemens KWU (67%). The plants must produce electricity at 10–15 Pf/kWh (6.7–10 ¢/kWh). While it considered that PAFCs over 10 MW operating on natural gas would not compete with GTCCs, Siemens was interested in the potential of 10 MW units operating on hydrogen-rich gas from chemical plants. Daimler–Benz was reported to be studying the possibility of using hydrogen PAFC systems combined with electrolyzers for off-peak electrical storage, peak-shaving, remote distribution, and power conditioning as an alternative to lead/acid batteries.

The European market was reviewed in 1991 [37]. By 1994, it was then expected that a total of at least 5 MW would be installed, including a 0.4 MW Westinghouse air-cooled, hydrogen-fueled PAFC in Norway, and a 1 MW MCFC, the 1 MW PAFC in Milan, and on-site units. The total was only 3.2 MW at the end of 1994, and consisted only of the planned on-site units and the Milan demonstrator. A 1994 update, which includes stationary FC activity, is given in Ref. [38].

7. Japanese PAFC experience

7.1. Electric utility demonstrations

Japan imports LNG for steam plants, which will be supplemented by new GTCC capacity. Because of the high cost of NG (about US$ 7.00/MMBTTU, US$ 6.70/GJ), the highest energy efficiency combined with cogeneration is desirable. The PAFC appeared to be an attractive option, and funding under the Ministry of International Trade in Industry's Moonlight Program started in 1980. During the 1980s, Japanese organizations were developing PAFC units for elec-

tric utility and on-site use under 50% cost-shared programs managed by the New Energy and Technology Agency (NEDO). Major activity was on demonstrations of 1 MW-class pressurized units and on the development of on-site units. During 1987 and 1988, the 1 MW Chubu unit, located at Chita Power Plant (2 Toshiba and 2 Hitachi CSAs, 6.3 atma and 205 °C) operated for 1018 h, and the 1 MW Kansai unit (2 Fuji Electric and 2 MELCO CSAs, 4 atma, 190 °C) operated for 2045 h. There were many incidents and problems during operation [13].

Apart from TEPCO's 11 MWe Goi plant, the next stage of pressurized PAFC development was the operation of the 5 MW Fuji Electric Kansai unit, which occupies three floors of one building. It was designed to operate at 6.0 atm at 200 °C, 0.746 V and 300 mA/cm², using 0.8 m² cells arranged in six CSAs. It has a mono-tube reformer of Haldor–Topsøe design, licensed to Kobe Steel. Design electrical efficiency is ≥ 46.6% LHV, and heat recovery efficiency 32% LHV (79% total). The target footprint is 0.27 m²/kW. The plant was about one year behind schedule due to interruption of the 1993–1994 PAC test, and power generation started in March 1995 [19]. This plant was sponsored by the PAFC Research Association (PAFCRA, consisting of Tokyo Gas, Osaka Gas, Toho Gas, Saibu Gas together with electric utilities).

PAFCRA is also supporting Toshiba to build and test a 1 MW atmospheric pressure cogeneration system in a six-year program which started in 1991. The unit was to operate at an electrical LHV efficiency of ≥ 40%, and an LHV heat recovery efficiency of ≥ 40%. The footprint of the 3.6 m high plant is < 0.1 m²/kW. The system has two 414-cell, 500 kW 1 m² stacks operating 0.25 A/cm² and at 205 °C. Toshiba had built a 1.0 m² CSA production facility in 1990. Manufacturing started in 1993, with field-testing proposed in 1995–1996 at the Tokyo Gas Tamachi site. By August 1994, all components had been delivered, and process and control (PAC) tests were in progress in 1994. The plant uses a single multi-tube reformer operating at a low (2.5:1) steam:carbon ratio, and will produce 25.5% of total LHV energy as steam [39]. Electric power production started in March 1995 [19].

Future commercial Toshiba electric utility plants would have a 0.08 m²/kW footprint and a 1.1 m³/kW volume to allow installation in the basements of urban buildings. They would have 1.1 MW CSAs rather than the 670 kW PC-23 design, and a transportable reformer in the 11 MW class [40].

7.2. Japanese on-site units

Fuji Electric Company and MELCO have taken the lead in developing on-site units, while Toshiba maintained its place as the partner of the Power Systems Division of United Technologies Corporation on their IFC joint venture. Toshiba is delivering PC25-type units of its own manufacture in Japan, the first being to the Kawagoe Power Station of the Chubu Electric Power Company in December 1992. It had accumulated 14 131 operating h by March 1995 [19]. The replacement Toshiba CSA for the PCX-2 unit at Shiba-ura

has already been noted. The performance decay on these CSAs between 4000 and 14 000 + h was negligible.

Ref. [19] gives a complete list of Japanese units and their operating hours up to March 1995. The total capacity of plants then operating was 24.75 MW. A total of 10.7 MW of this (not counting the non-functional stacks at Goi) were manufactured by IFC. The cumulative hours obtained on all units was then 1 135 595 h. A number of Japanese on-site PAFC units have now exceeded 20 000 operating h (see below). This represent half of the required stack lifetime for commercial applications.

7.3. Fuji electric on-site

Fuji Electric decide to concentrate on 50 kW on-site units in the late 1980s. An early FP-50 unit at Tokyo Gas started up in April 1990, and had operated for 2500 h by the end of August of the same year. Its reformer was a compact single burner, single tube system, and it incorporated five heat exchangers in two units using plate and fin technology. It showed an optimum electrical efficiency of about 41% (LHV) when the heat recovery efficiency was about 35% (total 78%) [41]. Tokyo Gas had seven FP-50 units and four 100 kW FP-100 units operating in 1994 with start-up dates from February 1991 to October 1993. As expected, later models performed with less trouble than earlier ones [32]. At the end of 1993, Fuji Electric had orders for over 65 on-site PAFC units from 50 to 500 kW, with a total capacity of 10 MW. By mid-1994, three 50 kW Fuji Electric FP-500 units had been installed, one at Osaka Gas and two at the Asia Taiheiyo Trade Center [19].

The Kansai Electric Power Company (KEPCO) installed six 50 kW Fuji Electric water-cooled NG units on Rokko Island near Kobe by November 1991 for tests in conjunction with solar and wind power facilities. Eight more were installed by March 1992. By the end of 1991, availability of the six generators had been around 85%, generating time had averaged about 5000 h, and average continuous generating time was about 1200 h. There were 187 operating stoppages, which required improvements [42]. In September 1995, the two oldest units had attained 24 000 and 21 000 operating h.

Two 50 kW Fuji Electric units (delivered in 1989 and 1990) operated on desulfurized naphtha at Idemitsu Kosen Co. [43]. A 200 kW version of the Fuji Electric power plant was designed to use methanol fuel for applications on the 300 inhabited small islands off the main Japanese coasts, in conjunction with diesel generators and photovoltaics. Its efficiency was 44.0% at full load, 45.0% at 75% load, and 40.7% at 50% load. Its NO₂ emissions were 2 ppmv. By 31 August 1990 it had operated for 3600 h and had produced 493 MWh at the Okinawa Electric Power Company location on Toka-shiki Island [44]. By September 1993, it had operated for 8449 h.

There are also four 50 kW Fuji Electric systems in Europe, at Enagas in Spain, at SNAM/Eniricherche in Italy, and at the Swedish utilities Vattenfall and Sydcraft. Initial problems

included self-commutation of the inverter when it sensed line fluctuations. This was corrected by modification of software. NO_2 emissions at 12% oxygen measured on the Vattenfall Fuji Electric 50 kW unit were normally in the 1.4–4 ppmv range, with peaks up to 8 ppmv. No degradation data were available [45]. Two 25 kW PAFC Fuji Electric CSAs had been assembled into systems by KTI in The Netherlands under Italian–Dutch–CEC sponsorship. Further work on this collaboration had been reportedly discontinued. The Baverian solar energy project (Bayernwerk, BMW, Linde, and Daimler–Benz), with 250–280 kW of amorphous silicon photovoltaics and a 50 kW MBB electrolyzer, includes a 70 kW Fuji Electric–KTI hydrogen PAFC system.

7.4. Mitsubishi electric company (MELCO) on-site

A 200 kW MELCO unit weighing 25 000 kg operated at the Plaza Hotel, Osaka from March 1990 to 31 October 1991 giving 13 038 generating h (1797 MWh), with 60 start-ups and a maximum continuous run of 2656 h. Electrical efficiency was 40.0% (LHV) at full load (89.5% total), and 35.0% at 25% load (76.0% total). Performance degradation was less than 5% over the total operating time, with 7% projected to 40 000 h [46,47]. Its measured NO_2 emissions were 4 ppm at 7% oxygen (dry basis), i.e. 1.2 g/MWh, with negligible SO_2 and particulates. Newer MELCO atmospheric pressure water-cooled CSAs showed excellent performance and stability, with average decay less than 2 mV/1000 h, with a 7% (50 mV) reduction in cell voltage from the initial value of 0.65 V (at 200 mA/cm^2, 205 °C, and 80 and 50% fuel/oxidant utilizations) projected at 40 000 h [48]. The same report gives data on the 100 kW methanol-fueled system sponsored by the Hokkaido Electric Power Company for use on isolated islands operated 4575 h (330 MWh) up to August 1990 with 245 stop-start cycles. Its total LHV efficiency was 88% (40% electrical, 41.2% at beginning of life) and its start-up time was 2 h (cold) and 1.5 h (hot). Its load following ramp rate was 30% per min, twice the requirement, and its NO_2 emissions were under 1 ppmv. The first pre-commercial 200 kW MELCO unit installed by the Kansai Electric Power Company on Rokko Island in 1992 had accumulated over 18 000 h by September 1995. Other 200 kW systems were installed in the KEPCO Research Center and at the Yanai Power Station of the Chugoku Electric Company in mid-1993 [19]. A summary of Japanese PAFC field trials to late 1993 has been published [49].

A 50% increase in current density (to 300 mA/cm^2) was shown in sub-scale (100 cm^2) cells and confirmed in 0.36 m^2 CSAs. The footprint of the 200 kW on-site unit was improved from 0.16 m^2/kW in the 1989 25 000 kg Plaza Hotel unit, which operated at 150 mA/cm^2 with a steam:carbon ratio for reforming of 3.5:1, to 0.15 m^2/kW in the later 1991 version (200 mA/cm^2), to 0.12 m^2/kW (250 mA/cm^2, steam:carbon 3.0:1), and finally to 0.08 m^2/kW (300 mA/cm^2, steam:carbon 2.5:1) was expected in 1996 and beyond. MELCO personnel expected that the improve-

ment in steam:carbon ratio would raise the output of 170 °C steam successively from 18 to 21%, then to 25%. All MELCO plants after 1992 had fully automatic control [50,51]. We should note the 300 mA/cm^2 ONSI PC25C has a 0.08 m^2/kW footprint. Early PC18s had a value of 0.2 m^2/kW, whereas the values for PCXs and PC25As were 0.2 and 0.11 m^2/kW. Current Fuji Electric systems have footprints of 0.1 m^2/kW [32]. The proposed large Toshiba atmospheric pressure system will have the same footprint (see above).

8. Ultimate PAFC system costs

We have seen that the ultimate determinant for the commercialization of a real-world PAFC is system capital cost. The US DOE decided in the mid-1980s that the PAFC was essentially 'pre-commercial'. However, in 1985 [11], the pressurized electric utility PAFC was still very far up the learning curve. Early units were expected to cost about US$ 6000/kW (1995). EPRI-generated studies assumed a learning curve with an 87% fall in cost per doubling in production, i.e. a relative cost equal to $kp^{-0.2}$, where k is a constant and p is the relative production. The cost of the pressurized PAFC was then expected to fall to the equivalent of US$ 3200/kW (1995) after production of about 100 MW by about late 1992, and to about US$ 1900/kW (1995) after production of about 45 units (500 mW) by mid-1995. About the year 2005, the capital cost was expected to fall to about US$ 1300 per kW (1995) [11].

In contrast, the first three prototypes of the proposed PC23 were originally offered by IFC at US$ 3600/kW (1986) or US$ 4800/kW (1995), and the next 20 units would be half that cost, i.e. US$ 2400/kW (1995). Was this realistic? At the time it seemed optimistic, but in hindsight it was probably correct. The way in which the cost of IFC fuel cell systems have fallen in real terms (US$/kW, 1995) as a function of time are shown in Fig. 1. The plot shows the logarithm of cost in 1995 dollars as a function of year. One point (for the 11 MW Goi unit), is somewhat uncertain, because of the rapidly changing value of the Japanese yen compared with that of the US dollar over the construction period. The message is that a real learning process, resulting in cost reduction, has occurred over the years.

To translate the results in Fig. 1 to an understandable learning curve, such as that assumed in the mid-1980s [11], we must use a plot of cost as a function of total component production. This can be done in various ways. Learning curves are usually expressed in terms of logarithm of production cost as a function of annual production rate, or as a function of cumulative production. In a thriving marketplace, both are approximately equivalent. While the PAFC is still far from being in a thriving marketplace, a cumulative production analysis is not inappropriate. However, a more realistic log cost–log cumulative production that the simplified one discussed above is appropriate for a close-to-commercial technology, in which present cost are not too far (i.e. a factor
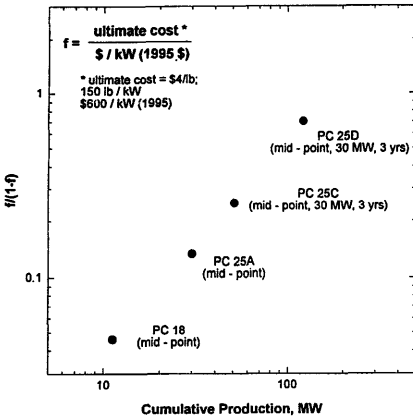
Fig. 1. Capital cost (mid-1995 dollars, logarithmic scale) of successive Pratt and Whitney Aircraft, United Technologies, and International Fuel Cells-ONSI on-site PAFC equipment as a function of time in years.

of two or three) from ultimate costs. It is best to use a logistic curve [52], in which cost (or other desirable parameter) is made a function of penetration towards the ultimate value. Thus, instead of the logarithm of cost as a function of the logarithm of cumulative production, we should plot a relative logarithmic cost function instead. This function is equal to the logarithm of $f/(1-f)$, where f is the ultimate possible cost of the technology divided by the present cost, both in US$/kW. Inevitably, guessing the ultimate cost poses problems, but the final result is not particularly sensitive to any assumed value. We may simply assume that an ultimate mass-produced on-site system, largely consisting of a mixture of structural mild steel, some stainless steel, and about 7 wt.% graphite, will cost US$ 10/kg (US $4.50/lb). The analogy would be the 'basic' version of a car, a utility truck, or the tractor of an 18-wheeler truck (17 500 lbs, US$ 75 000). This means that an ultimate extrapolation to a future 200 kW PC25+ system would make it cost US$ 600/kW and weigh 12 000 kg (27 000 lb). This ultimate weight and cost is not unreasonable, based on present projections.

The results of this modified learning curve plot extending from the PC18 through the PC25C to the proposed PC25D are shown in Fig. 2, estimated for the costs at the mid-point of production in each series of IFC on-site units. The slope of this curve is 1.12, and cost (US$ 1994/kW) is equal to $600(1+x)/x$, where $x=p^{1.12}/324$, where p is the total cumulative production in MW. For small x ($x=0.2$ for $p<40$ mW), cost approximates to $(2\times10^5)p^{-1.12}$ (US$ 1994/kW). This is a much steeper learning curve than that assumed in 1986. The latter was an 87% learning curve, in which costs falls by 13% per doubling of production (i.e. $\alpha p^{-0.2}$).

Fig. 2 corresponds to a 54% learning curve for small cumulative production volumes. In 1985, when IFC first proposed

PC23 guaranteed costs, total PAFC production was about 13.3 MW (a.c.), the total for the PC11, PC18, PC19, and the two 4.5 ME demonstrators. Thus, the midpoint cost for an additional three 11 MW PC23 units (totaling 29.7 MW at the mid-point of this series) could be predicted from the 54% learning curve to be US$ 5300/kW (1995). An additional 20 units (156.3 MW at the midpoint of the series) might have been available at an average cost of US$ 1367/kW (1995). Thus, based on the history of IFC's progress, which has occurred under non-ideal conditions with stop-start manufacturing due to lack of customer interest, high investment costs, no real planned mass production, and changing management teams, IFC's 1985 cost estimates were in retrospect probably conservative. Total IFC PAFC parts production to date (including the 11 MW Goi unit) is only about 40 MW, less than the size of a single large aero-derivative or medium-sized industrial gas turbine.

The percentage of total PAFC capacity (particularly CSA capacity) delivered to Japan by IFC–ONSI demonstrates the advance IFC's products have made towards commercialization in the world market. Native Japanese PAFCs still are priced in the US$ 10 000/kW range, based on the present trading exchange rate of about ¥100 per US$ at the end of 1995. Using the effective World Bank Purchasing Power Parity (PPP) exchange rate of ¥149 per US$ (World Bank, 1994) [9], this falls to an effective level of more than US$ 7000/kW for the effective comparative cost for on-site units. The cost must be reduced by a factor of four or five [19] to achieve a desired cost in the 200 000–250 000 ¥/kW range [53].

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[9] After falling to a low of ¥ 81/US$ in April 1995, the trade exchange rate was back to ¥ 97/US$ by mid-August 1995, and ¥ 105/US$ by the year's end. The PPP rate of course remained largely unaffected.
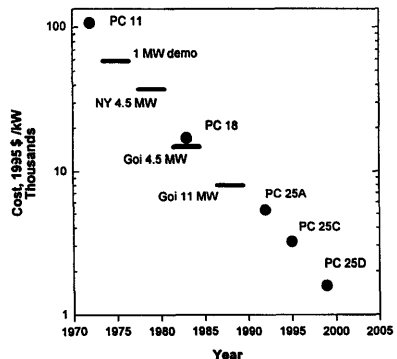

Fig. 2. Log-log logistic plot of reduced cost $(f/1-f)$ of UTC-IFC-ONSI on-site PAFCs as a function of mid-point of real or estimated cumulative production. $f=$ (ultimate learned-out cost)/actual cost. The costs are in constant dollars, and the ultimate learned-out cost is assumed to be US$ 600 (1995).

The PC25C promises to be an outstanding machine from the viewpoint of reliability and emissions, and seems assured of a place for small NG-fueled cogeneration equipment in the USA, in applications where it competes with electricity as delivered (rather than as generated), with an appropriate credit for on-site heat. The only criterion is whether the manufacturer can remain on the cost learning curve. There is every indication that this will be maintained. The cost of PAFC manufacture in Japan will also fall on the learning curve as production increases, but the US manufacturer should still remain ahead if it maintains the necessary commercial momentum. This suggests that imported US-built PAFCs may be very cost-effective in Japan, but the reverse will not be the case for Japanese imports to the USA.

9. The Japanese PAFC market

A 1990 estimate of the Japanese FC market was 10 to 100 MW by the year 2000. If the high end was attained, the MCFC capacity might then be 10 MW. By 2010, total PAFC and MCFC capacity was predicted to be 1–2 GW [54]. In 1991, market studies conducted by Japanese Government Agencies (the Agency of Industrial Science and Technology, AIST, and the New Energy and Industrial Technology Development Association (NEDO) were reported [54]. They assumed an imported LNG cost of ¥ 4/Mcal (¥ 956/GJ, ¥ 1008/MMBTU, or US$ 7.50/MMBTU at the then-trading exchange rate of ¥ 135/US$, or about US$ 6.75/MMBTU at the estimated PPP exchange rate in 1994 (World Bank Atlas, 1994). The resulting break-even costs of plants and electricity are therefore higher than US or European figures.

The allowable capital costs of a 37% LHV efficiency LNG steam boiler plant and of a 30% LHV 30-year life industrial diesel cogeneration plant were ¥ 210 000/kW and ¥ 220 000/kW (11991) respectively, i.e. US$ 2370/kW and US$ 2480/kW (1995) at the August 1995 trading rate, and US$ 1570/kW and US$ 1640/kW (1995) at the PPP rate. Assuming transmission and distribution credits of ¥ 15 000/kW, break-even costs for both cogeneration and electric utility dispersed 47.7% LHV electrical efficiency FC plants with a two-year CSA life were ¥ 190 000/kW. For a five-year CSA life, they were ¥ 260 000/kW and ¥ 280 000/kW, respectively. These three values correspond to US$ 2150/kW, US$ 2 940/kW, and US$ 3060/kW (1995) at the August 1995 trading exchange rate and US$ 1420/kW, US$ 1940/kW, and US$ 2090/kW (1994) at the PPP rate. For generators on remote islands, the break-even would be ¥ 220 000–260 000/kW.

The conclusion [53] was that the PAFC would succeed as a dispersed technology, whereas the more efficient, higher capital cost MCFC (see later) would become a central station technology. It is clear that PAFC capital cost is less of a problem in a Japanese context than it is in the USA. District heating systems in Japan currently represent only about 0.5% of total heat demand. Assuming cogeneration PAFCs are available, it was estimated that 1040 MW$_e$/year could be

used in urban development areas by the year 2000 and 840 MW$_e$ per year in new town areas. Customer-owned units supplying combined heat and power in individual new buildings were projected for units in the 1, 3 and 5 MW$_e$ sizes. No units in the sub-MW range, e.g. the IFC PC25, were considered. The markets for these PAFC units were evaluated at 510, 220 and 160 MW$_e$/year by the year 2000. Thus, total potential Japanese markets of 2400 MW$_e$/year for commercial cogeneration by the year 2000.

In June 1990, the Ministry for International Trade and Industry (MITI) published a report taking a long-range view of Japan's future energy supply and demand. It concluded that GNP and energy demand should be decoupled by enforcement of a conservation policy, which would change the elasticity factor from the present 0.98 to 0.42, so that a doubling of GNP should result in an increase in energy demand by only 33%, down from the recent value of 96%. To achieve this, cogeneration systems mainly supplied by fuel cells should be increased from a proposed capacity of 150 MW$_e$ by the year 2000 to 10.5 GW$_e$.

The Supply and Demand Committee of the Electric Power Industry published a report at about the same time which proposed an acceleration of nuclear capacity and the introduction of an optimized mix of power plants. This would include dispersed power generation using renewable energy sources, together with a large fuel cell generating capacity. The aim should be for a total installed fuel cell (presumably PAFC) capacity of 2250 MW in 2000, which would include 900 MW in commercial use and 300 MW in industrial use, with 1050 MW of dispersed electric utility units. The target cost for dispersed units would be ¥ 250 000/kW (1990). By 2010, 2800 MW should be in commercial use or only about 10% of the potential market identified in the AIST–NEDO report. Industrial use should include 2400 MW and utility use 5000 MW. Of the latter, the PAFC should be 3100 MW, newer high-temperature fuel cell (HTFC) technologies providing the remainder, giving the proposed total of 10 500 MW of installed fuel cell capacity.

In view of the potential market, MITI and NEDO encouraged Hitachi to re-enter PAFC development and manufacturing. In addition, the Japanese Government was supporting the PAFC by offering up to one-third of the cost of installation during the fiscal years 1992–1994 [55]. While only ¥ 800 million had been appropriated for this purpose at the beginning of 1992, the amount was expected to increase rapidly. At the 1993 Grove Fuel Cell Symposium in London, Rioji Anahara, then Executive Chief Engineer and Director of the Fuji Electric Company's fuel cell development program, and now Secretary-General of the Japanese Fuel Cell Development Information Center, Chiyoda-ku. Tokyo, stated that cumulative spending on fuel cells through the year 1996 (in millions of current-year ¥) would be 2590 for basic R&D, 2590 (100% government financed); 13 509 for pilot plants (100% government supported), 4650 for demonstration plants intended to accelerate commercialization (50% government subsidy), and 1270 for field trials (a 33% govern-

ment subsidy). The latter subsidy would be granted for the construction and operation of all PAFC fuel cells in Japan during the period of 1992–1994, with possible later extensions. This would also apply the fuel cell power plants built by off-shore developers [56]. Going beyond the MITI projections for the year 2010, he stated that Japan expected to eventually have 30 000 MW of central fuel cell power generation (in sizes from 50 kW to 11 MW), 15 000 MW of gas utility on-site capacity (from 12.5 kW to 1 MW), and 1000 MW of other capacity (in sizes from 4–200 kW) [56].

Today, it is improbable that the PAFC industry can expand at the necessary rate to fill the market identified in Japan by 2000 (or even 2005). However, even if its development is less than anticipated, some of the potential Japanese capacity might be provided by US developers, who have lower manufacturing costs. For the PC25C, a cost reduction of 33% is required to make it competitive in Japan, whereas indigenous products must have costs lowered by a factor of four to five [19].

10. Commercialization of high temperature fuel cells: the MCFC

10.1. USA: IFC

IFC was in a leading position in MCFC stack development in the early 1980s, but is no longer supported today by US DOE or EPRI [10]. After the failure to commercialize the pressurized PAFC in 1988, the American Public Power Association (APPA, 2200 small municipal utilities with a total capacity of 90 GW) identified dispersed fuel cells as a suitable future generating technology. In October 1988, the Association published the NOMO ('Notice of Market Opportunity'), which was aimed at fuel cell systems greater than 1 MW, with smaller dispersed units as appropriate. After evaluation of responses to the NOMO, the MCFCs being developed by Energy Research Corporation (ERC) was selected as the most suitable technology. ERC promised capital costs of approximately US$ 1500/kW$_e$ (1995) in 100+ MW/year production and 50% efficiency on NG. An efficiency of this order is attractive to compete with the GTCC. ERC founded the Fuel Cell Commercialization Group (FCCG) in 1990 as a users' group [57,58].

10.2. USA: ERC

ERC had established the Fuel Cell Manufacturing Corporation (FCMC), Torrington, CT, to manufacture internal

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[10] IFC's MCFC plans, for the present, are to work with Ansaldo srl in Italy, and Toshiba in Japan. IFC is not supported by US DOE or US utilities, but it has designed a 5 atma pressurized 1.8 MW system with advanced externally-manifolded lightweight cross-flow cells with fewer and simpler components to reduce cost. The system incorporated an anode feedback loop containing a reformer, which operated on sensible heat from the cell stack. Its planned cells were 0.75 m^2 (8 ft^2) active area. IFC granted its PAFC licensees, Toshiba, and Anslado the use of this new technology.

reforming CSAs, and the Fuel Cell Engineering Corporation (FCEC), to implement systems design and installation in 1990. The 'simplified plant' was designed in collaboration with Fluor–Daniel, Inc., using Jacobs Applied Technology for CSA packaging. After an initial scale-up to 0.37 m^2 (4 ft^2, active area 0.325 m^2), ERC standardized on a 0.56 m^2 (6 ft^2, active area 0.498 m^2) cell size for preliminary demonstrations. Preliminary work and plans were given in 1991 [57]. Initially 20 kW CSAs were tested, followed by 70 kW 0.37 m^2 234–cell CSAs. A 70 kW CSA was operated for 2000 h, including 1400 h (33 MWh) grid-connected at the Pacific Gas and Electric (PG&E) facility at San Ramon, CA, in May 1992. It operated at approximately 120 mA/cm^2 at 0.77 V (71 kW), with an overall polarization slope of 1.6 Ω cm^2. A similar CSA operated for 4000 h on coal gas at the Plaquemine, LA gasification facility [59]. There are plans to operate stacks on biogas and landfill gas, since EPRI notes that 749 US landfills have been identified with a potential capacity of more than 2 MW, with a total of 6 GW. A development update has been given recently [60]. In 1991–1992, Elkraft (Denmark) tested a 7 kW ERC CSA, and proposed a 100 kW or 2 MW unit. At the same time, Messerschmitt Boelkow Blohm (MBB) GmbH in Germany (now part of Deutsche Aerospace Airbus, in the Daimler–Benz Group) was planning manufacture of ERC CSAs and a 2 MW demonstrator using ERC CSAs [37]. These projects have been delayed.

A demonstration of PAFC system technology at IFC (then P&W) on the 1 MW scale, even if it was not entirely successful, first took place in 1977. Demonstrations of molten carbonate system technology on the same scale will not happen until early 1996. At that time, the 1.8 MW atmospheric pressure Santa Clara, CA, ERC unit should start to produce electricity. The plant is sponsored by five California utilities, US DOE, EPRI, and the National Rural Electric Cooperative. Start-up was originally planned for the late summer of 1995, but some slippage occurred in stack procurement. Twelve out of sixteen CSAs were ready by late August 1995, and hot system testing was in progress. All four-CSA modules were delivered between November 1995 and January 1996, and start-up was expected in February 1996.

The 258-cell 0.5 m^2 CSAs for this unit have been tested, and because they reform internally, they effectively serve as their own system. ERC has made very significant performance improvements with this technology. In 1985, it would have been expected to operate at 0.12 A/cm^2 and 0.73 V under 'reference gas' operating conditions, i.e. on natural gas reformate at about 75% utilization and on air with 30% CO_2 oxidant. Using a series of important advances, ERC could obtain this performance on practical system oxidation (about 10% CO_2) by early 1992.

The performance of the CSAs for the Santa Clara unit, for which groundbreaking took place on 7 April 1994, is expected to be 0.76 V at 133 mA/cm^2 at 75% fuel and 50% CO_2-in-oxidant (CO_2) utilization. Each internal-reforming CSA will therefore produce 130 kW. Future systems are expected to operate at 210 mA/cm^2 at the same cell potential

under the same conditions via careful control of internal resistance losses. This must be considered to be a major achievement. Stacks for such systems are expected to be scaled up by ERC to about 0.8 m^2, with about 300 cells, so that each CSA will deliver about 375 kW. Because of the use of internal reforming, the system behaves as if natural gas is used directly. Thus, its gross effective LHV efficiency at 0.76 V and 0.75% fuel utilization is $(0.76 \times 0.75)1.040$ (54.8%), where 1.040 is the LHV of methane. A d.c.–a.c. inverter efficiency of 97% and parasitic power losses bring the overall LHV efficiency to 49.8%, an attractive figure for a commercial system. The total cost of the Santa Clara project is US$ 46 million in current-year dollars, including 10 000 h of testing. US$ 16 million is for the fuel cell CSAs and modules (US$ 9000/kW). The cost of BOP for future 2 MW units, with a 20% discount for a run of 10, without extra engineering costs, was quoted at US$ 800–900/kW (1994–1995). Commercialization issues required the FCCG members to acquire 20 units (40 MW), with expansion to 35 units (70 MW), with 30 MW of further pre-commercial units, leading to eventual delivery of commercial plants in 1998. A recent update has been given [58]. The commercial target cost was approximately US$ 1350/kW (1995).

In December 1994, ERC was awarded a US$ 146 million contract (current dollars) by US DOE to build and operate a 3 MW demonstrator on Staten Island, NY, hosted by the New York Power Union. It was estimated that the system cost would be US$ 40 million, i.e. US$ 13 300/kW.

10.3. USA: MC-Power

The other major US developer, MC-Power, had a user's group (the Association to Commercialize Carbonate Technology, ACCT) consisting of 44 utilities, three independent power producers, five industrial firms, seven foreign members, and five others, including EPRI and GRI. Like ERC, MC-Power has been able to register a considerable performance increase in the cell level since 1990. MC-Power's 3 atma system uses the heat content of the anode exit stream to supply the enthalpy of reforming in a close-coupled flat-plate heat-exchange reformer developed by Ishikawajima–Harima Heavy Industries (IHI). It uses an internally-manifolded, 0.93 m^2 cell of 'Internally Manifolded Heat Exchanger', IMHEX® type. From 1988 to 1991, IGT, R&D member of the technology team consisting of Bechtel for BOP engineering and Stewart and Stevenson for factory packaging of systems, tested six successive 1000 cm^2 IMHEX® CSAs, culminating in a 70-cell version tested at MC-Power to check for any problems in vertical scale-up. At IGT, stack IGT-6 with 20 cells was tested at atmospheric pressure to 7163 h with an average decay (20 cells) of 18 mV/1000 h, and 4 mV/1000 h based on the best 17 cells. Performance in early 1994 at 3 atma on system gases was 743 mV at 200 mA/cm^2, at a fuel utilization of 75%, and oxidant utilization of 30%. The goal was 800 mV under the same conditions. The constant utilization polarization slope was 0.83 Ω cm^2. With the use of proprietary cathode and electrolyte additives to reduce nickel oxide cathode dissolution, MC-Power and IGT, both contend that no lifetime problem to 40 000 h will exist even at 3 atma pressure with similar system cathode gas compositions. This point is important, since it implies that nickel oxide cathode dissolution will not be an impediment to initial commercialization.

By 1994, MC-Power had operated 20 kW CSAs for 1000–2000 h at atmospheric pressure. Full size cells operate at 1.1–1.2 kW at atmospheric pressure (0.69–0.76 V) and at about 1.3 kW at 3 atma (0.8 V).

The first 250 kW demonstration was to be at the Unocal Research Center in Brea, CA, and the second at the Kaiser Permanente Hospital in San Diego. Due to siting problems in early 1994, it was decided that the second unit would be installed at Miramar Naval Air Station. The Unocal system had a conventional KTI reformer with an air-fired burner operating on an NG/air (not anode and cathode effluent) in a unit containing the hydrodesulfurizer. It used a prepackaged BOP skid. The 10 m × 20 m Miramar unit was to have an integrated reforming steam supply and an Ishikawajima-Harima Heavy Industries (IHI) flat-plate reformer. The catalytic burners in the latter operated on anode and cathode off-gas, giving higher efficiency and automatic differential pressure control between the anode and cathode exit gases in the CSA. The BOP (desulfurization, turbocompressors, cathode recycle blower, cathode recycle cooler, and heat recovery) would be skid-mounted, with other skids providing instrument air compression, purge gas storage, NG compression, and boiler feed water treatment. As in the Unocal plant, the inverter was to be a separate unit. The system uses an ambient-temperature Tokyo Gas Company catalyst for sulfur removal from natural gas. Both plants are sponsored by US DOE, EPRI, GRI, with participation of the South Coast Air Quality Management District (SCAQMD), Southern California Edison, Southern California Gas, and Unocal in Brea, and San Diego Gas and Electric at Miramar. A 1994 update has been given [61]. Start-up of the Brea unit was delayed in 1995, after an operational control problem occurred which resulted in stack start-up malfunction. As a result, simultaneous operation of both the Brea and Miramar plants is expected in 1996. Tests of 4000 operating h are expected.

Operation of a 1 MW MC-Power pre-prototype to be located at the Southern California Edison Highgrove Generating Plant in Grand Terrace, between Riverside and San Bernardino, CA, is expected in 1997. This unit is sponsored by US DOE, EPRI, Southern Cal Edison and PSI Energy. A three-year US DOE contact for US$ 104 million (current-year dollars) was awarded for the demonstrator in January 1995. This will contain two CSAs, since the maximum stack height is limited to 400 cells because of pressure drop in the internal manifolding. The aim is for an eventual CSA cost of US$ 450/kW (1995), of which materials cost will be 50%. A total system cost approximating US$ 1700/kW (1995) is

projected in quantities of 20–30 MW per year, i.e. approaching the commercial production range.

10.4. Japanese demonstrations

In Japan, pressurized 100 kW class CSAs with areas of 1.0 m^2 (single cell) and 1.2 m^2 (with four separate 0.3 m^2 cells per plate) developed by Ishikawajima-Harima Heavy Industries (IHI) and Hitachi, respectively, were tested ending in November 1993 at the developers' plants and at Akagi Stack and System Square [62,63], and there were plans for a 1000 kW demonstration with 2 IHI and two Hitachi CSAs, to start up at the Kawagoe Power station in 1997 [64]. MELCO is developing internal reforming systems under ERC license. Stacks in the 30 kW class have operated for 10 000 h [65]. The cost of operation alone of the 1 MW power plant demonstrator is estimated to be approximately US$ 150 million.

10.5. Europe

In Europe, The Netherlands program is in the lead, and a 250 kW demonstrator with two 1.0 m^2 internally-manifolded CSAs with FLEXSEP® bipolar plates is proposed. It will result from a collaboration between The Netherlands Energy Center (ECN), the Netherlands Fuel Cell Corporation (BCN), Stork Product Engineering BV, and Stork Alpha Engineering BV [66]. A recent update on the program has been given [67]. BCN believes the MCFC must compete in price with GTCCs at US$ 750–850/kW, and cannot do so if a 250 kW CSA continues to contain 1 m^3 of materials (about 6 metric tons, with a materials cost of about US$ 300/kW). However, the FLEXSEP® 1 m^2 bipolar plate (without current collectors) contains only 6 kg of materials (as ordered, including scrap). Plates by US developers are heavier. In Japan, the still-experimental IHI plate weighs about 20 kg/m^2, the Hitachi plate being even heavier. Power densities require further improvement, a step already taken by ERC (see above). However, ECN still has concerns about CSA lifetime [68], but its estimates differ from those of the US developers.

There is concern about the start-up capital required for European commercialization of the MCFC, SOFC, and PEMFC, which is estimated by the Commission of the European Union at US$ 1.7 billion (of which the Commission could supply 10%). In 1994 BCN suggested that US$ 330 million would be required to launch the MCFC. In the USA, ERC considered that US$ 200–250 million is required, with US$ 200 million already spent. The above are in mid-1994 dollars.

Ansaldo Richerche srl in Italy (ARI) and Tecnologia y Gestion de la Innovacion S.A. of Spain agreed to cooperate on MCFC development in July 1993, and signed an agreement with IFC in March 1994. A 100 kW demonstration with externally-manifolded 0.75 m^2 cells is planned, based on IFC technology [69].

11. The SOFC

The SOFC design closest to commercialization is the tubular Westinghouse system, which is technologically very advanced and shows excellent performance (approximately 0.7 V at 0.25 A/cm^2 and 0.66 V at 0.35 A/cm^2 on real system gases at 85% fuel utilization, representing a polarization of only 40 and 80 mV, respectively, including internal resistance). Its present level of scale-up is to 36 kW in a joint program between the Kansei Electric Power Company, Tokyo Gas and Osaka Gas [70]. The materials cost of the cells may be US$ 300/kW or less, but manufacturing costs per tube are very high. Some improvement in cost might be achieved by further scale of cell size beyond 1.0 m long, but there is a limit to this approach. The Westinghouse system cost approximately US$ 100 000/kW in 1992–1993. New simplified approaches to tubular cell production or the further development of flat SOFC systems are required to reduce cost. These are still in the laboratory stage in the USA, Japan, and Europe. An overview to mid-1993 is available [71].

12. Commercializing the PEMFC

The PEMFC descends from the GE non-fluorinated ion-exchange membrane cell for the 1965 Gemini space project [1]. Ballard Power Systems, Vancouver, BC, produced a pressurized hydrogen/air powered 5 kW Mk 5 CSA during the early 1990s. This cost approximately US$ 60 000/kW, and operated at 30 times the power density of the original GE H_2/O_2 system. These stacks were installed in a packaged 35 kW hydrogen power plant [72,73]. Similar units are operating a hydrogen-powered 120 kW bus (late 1992–early 1993) and a Mercedes–Benz MB 180 van (1993–1994). Ballard also built a 10 kW NG unit (40 kW peak power) with improved CSA technology, and Ballard was developing a pressurized 40% (LHV) 250 kW NG on-site plant, in partnership with the Dow Chemical Company [73] [11].

It is claimed that pressurization and the lack of a steam system yield a smaller footprint and a simpler and cheaper product [72]. However, it must operate at a high cell voltage to achieve the required electrical efficiency. The use of pressure in a system with no useful waste heat increases current density at constant voltage, but not at constant efficiency, since it requires parasitic power. In consequence, an atmospheric pressure PEMFC operating at 0.73 V would have the same efficiency and CSA footprint as a pressurized system operating at 3 atma and 0.8 V. It would also have the same efficiency as a PAFC operating at 0.65 V, but it would not be able to produce waste heat in the form of 170 °C steam for double-action chillers, but only 60 °C hot water. It remains to be seen whether this will be economically attractive for large on-site applications, although it may be applicable to

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[11] The Dow Chemical Company decide to withdraw from the project in 1995, stating that it did not fit its commercial plans.

TARGET-type domestic installations which are grid-connected for peak loads.

System designs, including those of high-efficiency reformers, have been reviewed [74]. Reducing the cost of BOP poses the same problems as those in the PAFC. However, PEMFC CSA costs are not quite the same. In general, pressurized systems require filter-press components, which a generally made from graphite is in the PAFC. However, the PAFC requires pure graphite for operation at 200–205 °C, where the PEMFC operating at 65 °C does not. Small (250 cm^2) atmospheric PEMFC require much smaller gas channels, hence thinner and light bipolar plates, than those of the large (0.46 m^2) atmospheric pressure PAFC. In principle, the PEMFC could use conducting plastics, especially those containing graphite fibers. Ballard's 1991–1992 Mk 5 water-cooled CSA uses machined graphite plates of 400 cm^2 area, of which 232 cm^2 is active. The plates weigh about 8 kg/m^2 of active area, and additional plates are required in the CSA for humidification and for cooling system parts. For a total active area per 5 kW CSA of 0.93 m^2, the weight is 45 kg, of which active fuel cell components (electrodes and electrolyte) are 1.3%, graphite parts are 25%, and heavy end-plates and tie-bars to resist pressure (about 600 kgf) represent the balance. The use of thinner cells can more than double the power output from the same weight and volume, giving a power density of about 250 W/kg (290 W/l). This version (Mk 13) is being used in the Phase 2 Ballard bus. A commercial version for a vehicle will require at least twice this power density to be competitive. In 1994, Ballard operated a stack also weighing approximately 45 kg with thinner components, which produced 10 kW (500 W/kg, 570 W/l). The ultimate goal for automobile applications after the year 2000 is 1000 W/l. At the 1995 Grove Fuel Cell Symposium in London, Ballard announced that it had developed a stack with even thinner and lighter components with a greater percentage of active area in a collaborative effort with Daimler–Benz AG. This operated at a lower pressure than 3 atma, at a higher unit cell voltage (0.65 V instead of 0.58 V), and presumably at a somewhat lower current density than about 1 A/cm^2. A 45 kg, 32-l CSA could then produce 32 kW. This must be considered to be a remarkable achievement, even though it still used a high platinum loading (see below).

An atmospheric pressure PEMFC would not require the heavy structure (or heavy pressure vessel) of a pressurized system, and could be made from inexpensive materials (graphite–plastic, US$ 11/kg, graphite filters, US$ 44/kg, aluminum sheet, US$ 5/kg). Lightweight bipolar plates and cooling plates weighing less than 1.6 kg/kW (0.73 V, 0.3 A/cm^2, i.e. 3.5 kg/m^2) can be designed. Electrodes today contain 0.1 kg/kW of graphite fibers in the form of cloth. Structural materials cost would be US$ 22/kW. The above performance has been demonstrated at atmospheric pressure in small cells using 0.05 mg/cm^2 platinum loadings on carbon [75]. Even at today's carbon-supported catalyst price (about US$ 1300 per troy oz, 250% greater than ingot platinum), loadings of 0.05 mg/cm^2 (cathode) and 0.025 mg/cm^2

(anode) represents only US$ 12/kW, so that the total materials cost without the PEM electrolyte membrane is US$ 34/kW. Using robotic machinery with a labor input similar to that in the automobile industry, the total assembly cost could be as low as US$ 4/kW, i.e. US$ 38/kW overall. However, the PEM electrolyte itself costs US$ 400–1000/kW today. This price must clearly fall by more than a factor of ten to make the system practical, especially for vehicle applications. Membrane developers believe that this will be possible, and alternative inexpensive chemistries are being explored [72,76–79].

13. Conclusions

A recent report for the US DOE [80] has examined some of the problems of fuel cell commercialization in detail. The only factor now limiting commercialization of fuel cells (or at least the PAFC) appears to be capital cost. Manufacturers are making great efforts to reduce costs, as is illustrated by that of the IFC PC25C. The nature of the Japanese market, the high Japanese competitive costs, and the ability of the Japanese users to demonstrate technology will greatly aid commercialization efforts. Indeed, the PC25C is only 50% more costly than a truly competitive power plant for on-site cogeneration purposes in Japan. Experience shows that learning curves have been much steeper than was previously assumed, so that costs will be acceptable by 1998 in Japan, and by 2005 in the USA and in Europe. All is required is production volume, along with ingenuity.

Japanese interest in demonstrating all technology before commercialization, whether commercially practical at the time or not, will help to create a market there. The European attitude towards testing is 'do not demonstrate impractical technology'. The US attitude is somewhere between that in Japan and in Europe. This difference in attitude was summarized by Ryoji Anahara as follows: 'European people consider before they walk, American people consider while walking, and Japanese people consider after walking' [56]. Japanese organizations have certainly shown a very open attitude to technology, since about 66% of currently-operating PAFC capacity in Japan has been designed and manufactured by IFC. Japanese government demonstration credits are available to the products of off-shore developers. Anahara [56] stated that the R&D philosophy adopted by Japan Government was different from that elsewhere. It could be characterized as 'Total Development' involving MITI, NEDO, the electric and gas utilities and manufacturers, involving all aspects of development. The industry in Japan was being helped by the enlightened attitude of the electric and gas utilities, and by the fact that the fuel cell developers are vertically integrated electric equipment manufacturers, possessing expertise in areas varying from robotics to electronic controls. These 'Total Development' philosophy had enabled the Japanese developers to catch up very quickly. The aims for commercialization would be increased power density,

longer CSA life, improved current density distribution, acid management, and improved materials, as well as plant sim plification and standardization, improved mass production techniques, and quality control. Much of the final cost is labor for assembly, so parts count and labor costs need further attention.

In the past, potential markets have been misunderstood and misinterpreted. It has been pointed out that 'false-start' commercialization under these conditions can be counter-productive [82]. Developers must be aware of paradigm changes (as so now called, i.e. changes in business and economic opinion). These include emphasis on quality of life, low pollution, silence, and decoupling of GNP growth and energy growth. The emphasis on greenhouse gas reduction is also part of the emissions paradigm. Related to these are the effect of unusual disruptions in economic activity and their effects on potential markets, such as the two negative effects in 1974 (which decoupled energy and growth) and in the early 1980s (when energy prices declined, making high efficiency less important). Developers must understand that the value of on-site systems is strongly site-dependent, and that the customer should define the market, not the developer. Users' Groups are important for defining the market [82]. Markets and customers change with time. A future electric power distribution company may not be interested in dispersed generation, but a gas distribution company may (cf. Enron with IFC). Local regulations for siting and licensing may also differ (e.g. between the USA and Japan or Germany, Ref. [29]). The requirements for straightforward and rapid licensing must be built into the equipment.

There is no 'natural' market for fuel cells. Over the years excuses for a particular type of market have been given. However, in all markets there will be competition, and developers must know the competition. Developers must know their technology and its limitations, to avoid problems such as those which happened with the PC18 cooling system and the Goi 11 MW CSAs. The benefits of the new technology must be exploited, and its inherent risks must be managed. However to spread the risks, Government support is critical [81]. The risks are financial, political, and technical.

From the latter viewpoint, it is fortunate that CSAs, the primary product and primary interest of the FC developer, behave so well. Cost reduction and reliability improvements for BOP must be emphasized. For this vendor suppliers' groups are important. This has been emphasized in Japan. Finally, excellent field support is essential, cf., that for the PC25A by ONSI [31]. Recent engineering developments have been outstanding, and PAFC commercialization will occur at the end of the decade, to be followed by the MCFC and the SOFC, which are 20 years and 30 years behind, but which will catch up, thanks to the experience gained with the PAFC and the desire to avoid previous mistakes.

In 1991, the Japanese fuel cell market for the year 2000 was estimated at 2.25 GW, and 10.5 GW in 2010 [53,56]. Total projected capacity additions in Japan by 2000 were estimated at 46 GW, of which distributed generation and

cogeneration would be 14 GW. Corresponding figures for distributed generation and cogeneration in North America and Europe were 62 GW and 40 GW, with a world total of about 200 GW [82]. This expansion of new dispersed capacity can only favor fuel cell systems, provided that they have competitive costs.

Finally, the ultimate market is the electric vehicle, for which a CSA of less than US$ 50 kW will be required to compete with the internal combustion engine. This should be possible with an advanced PEMFC with a less costly electrolyte.

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