Annex 1.

Case example of traditional regulation of the electric power sector

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This document can only be used in the context of the MIT Course ESD.162/6.695/15.032 “Engineering, Economics and Engineering of the Electric Power Sector” and the Comillas Course “Regulation of the electric power industry” and cannot be distributed without the explicit permission of the authors.
The traditional system for regulating the electricity industry is the outcome of many years of analysis, effort and regulatory experience from which much can still be learnt.

The electricity industry is not only enormously complex, both economically and technically speaking, but is a key factor in the economic and social development of any society. From its inception in the early twentieth century and throughout the history of the industry to its present maturity, enormous effort went into improving and optimising decision-making and operating processes to develop what is known today as traditional regulation. In order to introduce the traditional regulatory framework avoiding generalizations, this annex has taken the electricity industry in the USA in the early nineteen eighties as a specific example.

The information contained in this annex is particularly relevant for the following reasons: firstly, the electricity industry in the USA, especially in the years mentioned, was an archetype of traditional regulation. Indeed, for many years prior, it had (both federal and state-wide) regulatory bodies that had conducted in-depth analyses to optimise electricity industry organisation and develop its regulatory components. Moreover, the size of the industry in the USA and the large number of companies and regulators involved made it possible to devote enormous resources to such optimisation and continuous regulatory upgrading. Traditional regulation, with a diversity of formats, currently is the regulatory framework of choice in many countries of the world, including about one third of the states in the USA.

The time frame chosen for analysing the industry is particularly relevant, since in the early nineteen eighties not only had traditional regulation reached its zenith in the USA, but at the same time was the subject of the initiatives and studies that would later pave the way for the present liberalisation of part of the electricity business. Indeed, the PURPA\(^2\) act, approved only a few years before, was the first step towards what would develop into a general questioning of traditional procedures.

Expansion and operating planning in traditional regulatory environments, not dealt with in this annex, were briefly explained in chapter 1 of this book, which introduces the concept of decision-making hierarchy based on long term, medium term, short term and real time horizons. That brief discussion provides an overview of the general framework in which such decisions are implemented.

This annex addresses the analysis of the methods usually employed in North American electricity companies to establish electricity rates. Be it said from the outset that the industry in the USA was characterised in those years by enormous variety, geographically and historically speaking, and that the present discussion focuses on the most representative forms of the traditional method, without taking more than a cursory

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\(^2\) Public Utility Regulatory Policies Act: federal law enacted in 1978 in the USA that initiated the transformation of the electricity industry, indicating the need for more efficient rate design, authorising qualifying facilities (distributed generators using renewable sources or CHP systems remunerated on the basis of avoided cost), and so on.
look at the novelties that had then begun to shape the industry as it is known today. Consequently, this annex is structured as follows:

The first section is an introduction to the electric power generation industry in the USA in the early 1980s: structure, organisation, regulatory bodies and basic ratemaking issues. The four parts that follow are devoted to specific issues.

The second section describes the revenue requirements method, which was universally used in the 80s (and still now in numerous states) in the USA to determine cost of service, although with variations in its specific application.

The third deals with ratemaking for the sale of electric energy to a utility’s customers (end consumer sales), a process that was subject to the legislation in effect in the respective state.

The fourth section discusses the establishment of rates for wholesale energy sales (energy allocations and purchases in inter-utility energy exchanges and sales to distributors) among electric utilities, regulated by the federal (i.e., central) government.

The fifth section describes the organisation of power pools, more or less formal groupings of US electric utilities with varying levels of integration, and intra-pool energy exchanges. These pools, the predecessors of today’s regional transmission organizations in the US, which were governed at the time under a traditional regulatory scheme, now operate as competitive markets run by independent system operators.

The sixth and last section offers a critical evaluation of the traditional method of electricity regulation.
A1.1. THE ELECTRIC POWER SUPPLY INDUSTRY IN THE USA: INTRODUCTION

A1.1.1. Introduction

This first section of the annex contains a brief description of the most prominent characteristics of the complex American electric power supply system as it stood in the nineteen eighties. The physical features of the overall US system of generation, transmission and distribution, and the number, ownership and organisational structure of the different utilities operating at the time are described in subsection A1.1.2. Electricity industry regulatory institutions and their powers, particularly as far as ratemaking is concerned, are discussed in subsection A1.1.3. Subsection A1.1.4 summarises the basic characteristics of electric power rates in the US and introduces the subjects addressed in the following four sections: cost of service, wholesale energy sales, rates by each type of consumer and power pools.

The two figures below show the typical configuration of vertically integrated utilities, sometimes with embedded distribution companies connected to them, the spontaneous relationships between them (Figure 1) and the structured and coordinated transactions that take place when companies choose to function within a “power pool” (Figure 2).

Figure A1.1. Typical configuration of vertically integrated utilities

Figure A1.2. Power pools: a higher form of organisation
A1.1.2. Basic characteristics

The most characteristic features of the American electricity industry in the 1980s can be summarised as follows:

- There were nearly 3,500 utilities, whose ownership was private, public or co-operative. The numbers of each and their relative weight in the system as a whole are shown in Table 1.

- These utilities' generation plants and transmission grids were grouped into three large non-connected geographic systems: Eastern Interconnection (76% of the total), Western Interconnection (17%) and the state of Texas (7%).

- The American electricity system, which comprised the above three physically independent but synchronically operated systems, had an organisational structure that can be broken down as follows:
  - The 9 regions pertaining to the National Electric Reliability Council (NERC), an organisation created in 1968 to enhance the reliability and security of electric power supply in the USA. The electric utilities in each of these regions co-ordinated the planning and operation of their respective systems to attain a suitable level of reliability.
  - Natural groupings (not necessarily power pools) of electric utilities closely inter-related through energy exchanges, strong interconnections, geographic proximity, co-ordinated operation and so on. The overall system was divided into 26 such regions, further to the NERC classification (4).
  - Power pools, i.e., formal organisations established by two or more electric utilities to improve their economic performance and short-, medium- or long-term security and/or reliability. The degree of inter-utility integration ranged from simple rather unspecific agreements on energy transactions for reasons of economy to detailed arrangements for co-ordinated operation and planning among pool members. At the time there were around 30 power pools in the USA.
  - Individual electric power generation, transmission and/or distribution companies (see Table 1). Some private and most of the municipal and co-operative utilities were mere distributors of electricity, with no generation or transmission facilities of their own. There were six federal agencies (the Tennessee Valley Authority, the largest electric utility in the USA, among them) that generated electric energy in federally-owned facilities, all of which was then sold wholesale to other electric companies.

- The combined generating capacity of these three systems was on the order of 590,000 MW. The ten largest utilities accounted for 25% of this capacity, the 30 largest for 50% and the 100 largest for a little over 80% (4).

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3 The most authoritative sources for this type of information are the statistical surveys published from time to time on the US electricity industry, such as (22, 4, 13, 18, 12).

4
The 100 largest utilities had capacities ranging from 1,500 MW to 30,000 MW. The generating capacity of the 100 smallest that generated power was under 1 MW in all cases. Of all the other utilities that generated electricity, around 100 had capacities ranging from 250 to 1,500 MW and around 700 fell in the 1 MW to 250 MW category (4).

The peak demand in 1979 was 400,000 MW, and peak consumption 2.4 x 1012 kWh; 47% of this energy was produced with coal, 14% with nuclear energy, 16% with fuel-oil, 12% with gas and 10% with hydraulic power (4).

A substantial volume of electricity was sold in inter-utility wholesale transactions. In 1979, such sales in the private sector came to 18.5% of the net power generated by that sector, and in the system as a whole they accounted for 30% of total net generation.

Capital expenditure in 1979 amounted to $3.4 \cdot 10^9$: 73% in generation, 10% in transmission and 19% in distribution. In 1969 these percentages were 50%, 19% and 28%, respectively (4).

The following statistical tables provide a quantitative overview of the most prominent features of the American electricity industry in the early nineteen eighties. Most of these tables were taken from reference (18).

Table A1.1. Ownership structure of the US electricity industry in 1980, taken from (44)

<table>
<thead>
<tr>
<th>Ownership</th>
<th>Number of companies</th>
<th>Generating capacity</th>
<th>Total generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Private utilities</td>
<td>237</td>
<td>78.0</td>
<td>78.0</td>
</tr>
<tr>
<td>Co-operatives</td>
<td>960</td>
<td>2.5</td>
<td>2.8</td>
</tr>
<tr>
<td>Federal systems</td>
<td>6</td>
<td>9.6</td>
<td>10.3</td>
</tr>
<tr>
<td>Municipal utilities</td>
<td>2,248</td>
<td>5.6</td>
<td>3.8</td>
</tr>
<tr>
<td>State projects</td>
<td>–</td>
<td>4.5</td>
<td>5.2</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,451</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>
Table A1.2. Financial information on 31 December 1980 and 31 December 1979 (billion dollars) (18)

<table>
<thead>
<tr>
<th>Operating account</th>
<th>1981</th>
<th>1980</th>
<th>% increment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity industry revenues</td>
<td>118.1</td>
<td>100.8</td>
<td>17.3</td>
</tr>
<tr>
<td>Electricity industry expenses</td>
<td>101.2</td>
<td>88.4</td>
<td>17.0</td>
</tr>
<tr>
<td>Electricity industry profit</td>
<td>17.0</td>
<td>14.4</td>
<td>18.5</td>
</tr>
<tr>
<td>Other profits and deductions</td>
<td>4.7</td>
<td>3.9</td>
<td>20.3</td>
</tr>
<tr>
<td>Net profit</td>
<td>12.7</td>
<td>10.7</td>
<td>19.2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Source of funds</th>
<th>1981</th>
<th>1980</th>
<th>% increment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net profits</td>
<td>12.7</td>
<td>10.7</td>
<td>19.2</td>
</tr>
<tr>
<td>Non-cash credits</td>
<td>8.3</td>
<td>7.4</td>
<td>11.5</td>
</tr>
<tr>
<td>Total working capital</td>
<td>21.0</td>
<td>18.1</td>
<td>16.1</td>
</tr>
<tr>
<td>External funds</td>
<td>23.3</td>
<td>22.0</td>
<td>5.8</td>
</tr>
<tr>
<td>Other</td>
<td>3.5</td>
<td>3.2</td>
<td>11.6</td>
</tr>
<tr>
<td>Total funds obtained</td>
<td>47.6</td>
<td>47.3</td>
<td>10.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Application of funds</th>
<th>1981</th>
<th>1980</th>
<th>% increment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction and investment</td>
<td>28.1</td>
<td>26.4</td>
<td>6.8</td>
</tr>
<tr>
<td>Dividends</td>
<td>9.8</td>
<td>8.8</td>
<td>14.4</td>
</tr>
<tr>
<td>Debt repayment</td>
<td>5.9</td>
<td>4.8</td>
<td>23.9</td>
</tr>
<tr>
<td>Other</td>
<td>3.9</td>
<td>3.5</td>
<td>11.8</td>
</tr>
<tr>
<td>Total funds applied</td>
<td>47.2</td>
<td>47.3</td>
<td>10.5</td>
</tr>
</tbody>
</table>

Table A1.3. Tangible fixed assets on 31 December 1981 (billion dollars) (18)

| Steam plants | 5.41 |
| Nuclear plants | 2.78 |
| Hydroelectric plants | 0.08 |
| Other fixed assets, generation | 0.09 |
| **Total fixed assets, generation** | **8.36** |
| Transmission | 2.16 |
| Distribution | 4.06 |
| General | 0.64 |
| Experimental plants | 0.03 |
| **Total fixed assets for production** | **15.25** |
| Nuclear fuel | 0.65 |
| Fixed assets in progress | 9.00 |
| Other | 0.89 |
| **Total tangible fixed assets** | **25.79** |
Annex 1. Case example of traditional regulation of the electric power sector

Table A1.4.a. Ownership structure (private utilities) on 31 December 1981 (billion dollars) (18)

<table>
<thead>
<tr>
<th>Ownership Structure</th>
<th>Billion dollars</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term debt</td>
<td>115.42</td>
<td>50.3</td>
</tr>
<tr>
<td>Preferred shares</td>
<td>26.57</td>
<td>11.6</td>
</tr>
<tr>
<td>Share capital</td>
<td>61.19</td>
<td>26.7</td>
</tr>
<tr>
<td>Subsidiary reserves</td>
<td>21.27</td>
<td>0.6</td>
</tr>
<tr>
<td>Reserves</td>
<td>24.99</td>
<td>10.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>229.47</strong></td>
<td><strong>100.0</strong></td>
</tr>
</tbody>
</table>

Table A1.4.b Installed generating capacity in the USA, 1972-1981 (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Electricity industry</th>
<th>Class A and B private companies</th>
</tr>
</thead>
<tbody>
<tr>
<td>1972</td>
<td>399,606</td>
<td>312,067</td>
</tr>
<tr>
<td>1973</td>
<td>439,675</td>
<td>345,469</td>
</tr>
<tr>
<td>1974</td>
<td>475,888</td>
<td>375,348</td>
</tr>
<tr>
<td>1975</td>
<td>508,252</td>
<td>394,850</td>
</tr>
<tr>
<td>1976</td>
<td>530,999</td>
<td>414,265</td>
</tr>
<tr>
<td>1977</td>
<td>557,012</td>
<td>434,467</td>
</tr>
<tr>
<td>1978</td>
<td>579,157</td>
<td>447,447</td>
</tr>
<tr>
<td>1979</td>
<td>598,298</td>
<td>456,619</td>
</tr>
<tr>
<td>1980</td>
<td>613,546</td>
<td>478,268</td>
</tr>
<tr>
<td>1981</td>
<td>634,808</td>
<td>480,325</td>
</tr>
</tbody>
</table>

Table A1.5. Private electricity company revenue structure, 1981 (18)

<table>
<thead>
<tr>
<th>Sale ratios for domestic users</th>
<th>88.2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage of customers</td>
<td>31.8</td>
</tr>
<tr>
<td>Percentage of revenues</td>
<td>26.4</td>
</tr>
<tr>
<td>Percentage of sales in kWh</td>
<td>8,277</td>
</tr>
<tr>
<td>Average yearly sales in kWh per customer</td>
<td>513.11</td>
</tr>
<tr>
<td>Average yearly turnover per customer ($)</td>
<td>0.0629</td>
</tr>
<tr>
<td>Average revenues per kWh sold ($/kWh)</td>
<td>0.0629</td>
</tr>
</tbody>
</table>

Sales ratios for commercial users

| Percentage of customers | 10.9 |
| Percentage of revenues  | 25.9 |
| Percentage of sales in kWh | 21.3 |
| Average yearly sales in kWh per customer | 53,987 |
| Average yearly turnover per customer ($) | 3,393.40 |
| Average revenues per kWh sold ($/kWh) | 0.0629 |

Sales ratios for industrial users

| Percentage of customers | 0.5 |
| Percentage of revenues  | 26.5 |
| Percentage of sales in kWh | 32.1 |
| Average yearly sales in kWh per customer | 1,674,392 |
| Average yearly turnover per customer ($) | 71,390,56 |
| Average revenues per kWh sold ($/kWh) | 0.0426 |
In 1981 the average rate of return on American private electric utilities’ rate base came to 9.1%.

A1.1.3. Regulation

In the market economy environment prevailing in the United States in the 1960s and earlier, the electric power supply industry was one of the most heavily regulated in the various areas of its business. This trend intensified in the nineteen seventies due to growing public interest in issues such as the environment, security, quality of service, scarcity of fossil fuels and cost of electricity.

The following areas of the electricity industry were regulated by local, state and federal institutions in the USA:

- Rates for the wholesale and retail sale of electric power.
- Land use, in particular with respect to facility siting.
- Environment.
- Financing.
- Fuel.
- Electric utility organisational structure.
- Electricity network characteristics and location.
- Power Pools.

The specific regulation of these areas was incumbent upon the respective local, state or federal level.

Federal

The federal government is constitutionally empowered to regulate interstate trade and control federal land. Federal regulation of the electricity industry was governed by a series of laws enacted by Congress, namely: the Securities Act (1933), Securities Exchange Act (1934), Public Utility Holding Company Act (1935), Federal Power Act (1935) and Public Utility Regulatory Policies Act (1978, i.e., at the dawn of the period considered here). These laws were applied and enforced by independent agencies, whose powers and functions at the time are described below:

- FERC (Federal Energy Regulatory Commission) is an independent agency under the aegis of the Department of Energy with broad powers to regulate interstate energy transmission and wholesale electric energy transactions. The FERC had authority over the rates charged in interstate electric power sales and the rates for energy generated in federal projects were also subject to FERC approval. When deemed to be in the public interest and at the request of an electric utility or state agency, the FERC could order electricity system interconnection and energy sales. Power pool agreements, intra-pool energy exchange prices and specifications, as well as the rules on internal pool organisation had to be approved by the FERC. The commission was the key federal regulatory body for electricity ratemaking.
Annex 1. Case example of traditional regulation of the electric power sector

- SEC (Securities and Exchange Commission) has jurisdiction over holdings (a holding owns several electric utilities, which it usually operates jointly) and regulates their organisation. This commission is also empowered to establish financial regulations for private electric utilities in areas such as ownership structure, bond issues, mergers and asset control.

- ERA (Economic Regulatory Administration) is a Department of Energy agency that regulates electric energy imports and exports, the procedures to be followed in emergency situations, voluntary co-ordination among electric utilities and long-term electricity industry planning.

- EPA (Environmental Protection Agency) establishes rules on the environmental impact of electric power generation and transmission.

- NRC (Nuclear Regulatory Commission) regulates the construction and operation of nuclear plants through its licensing process.

**State**

The powers of state public utilities commissions (PUCs) with jurisdiction over the electricity industry, including regulatory development and enforcement, depended largely on the laws in force in each state. As a general rule, their chief functions included regulating: retail electric power rates, control over bond issues and environmental protection. Of the 47 state commissions with authority to regulate private electric utilities’ retail power sales, 16 were also authorised to regulate public and municipal companies and 25 to regulate co-operatives (4). In such cases the state commission was authorised to require approval prior to the entry into effect of new rates, suspend rate modifications and initiate audits of rates in place.

Generally speaking, state commissions only authorised rate rises when a utility’s net operating investment (rate base) increased or when operating costs took an upward turn. Rights issues and long-term debt generally had to be approved by the respective state commission, which had to be persuaded that the investment in new facilities was justified and the company’s subsequent financial situation acceptable. The decision-making procedure included public hearings.

**Local**

Local level regulation of the electricity industry was uneven, ranging from nil activity to strict control of aspects such as the environmental impact of electric energy transmission and generation or the rates charged for electric power by municipally owned utilities, local public companies and co-operatives.

Reference (2) contains a detailed discussion of the specifics of electricity industry regulation in the USA in those years. A critical analysis can be found in references (26, 44).

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4 Public Utilities Commission: state public service regulators in the USA. They are competent in the area of end consumer rate design within their respective states and are largely independent of federal regulators.
A1.1.4. Electric power rates: key questions

In the USA, as in many other countries with a privately owned electricity industry, a series of general criteria was followed to determine “fair” electricity rates. Further to these criteria, some of which may clash in practice, electric power rates were supposed to (11):

• Compensate electric power suppliers for the service provided and expenses incurred.

• Equitably distribute costs among all users, as far as practical given the limitations of metering and similar facilities.

• Provide a reasonable return on capital and attract new resources to finance any new facilities needed to cope with the demand growth.

• Reward service quality and system operating efficiency.

• Promote revenue stability over time to facilitate planning for user and utility future.

• Be sufficiently simple for utilities to readily apply them and consumers to readily understand them.

Ratemaking can usually be broken down into two stages: obtaining the average rate and formulating the rate structure for each type of user. US regulatory commissions traditionally focused on determining the total revenues a utility was to receive for energy sales, along with its cost of service, to attempt to ensure that it obtained a reasonable – neither excessive nor insufficient – return on its capital. This process typically comprised the following steps: 1) establishment of the rate of return on capital and the rate base; 2) determination of the costs incurred: operation and maintenance, depreciation, return on capital and taxes; 3) computation of the average rate level that would ensure the recovery of these costs. This is known as the revenue requirements procedure. Regulatory commissions also usually took an interest in the question of the allocation of total costs to different types of users: domestic, industrial, commercial and so on; nonetheless, as a general rule they did not actively exercise their regulatory powers in this connection.

The revenue requirements method for determining cost of service was applied to obtain both retail and wholesale rates. Nonetheless, the rates for a number of wholesale energy transactions were set by other ad hoc procedures tailored to each type of transaction (see section 4) in a manner such that the above costs were not all fully reflected in the selling price, or at least not with their full impact. This was the case for transactions that involved no present or future obligations for the utility comparable to the obligations inherent in its own load, in particular with regard to maintaining suitable reserves to guarantee its short- and long-term commitments. Emergency situations were a typical example of this type of operations, and so-called economic transactions another. The latter consisted in the exchange of unconditionally interruptible power between two companies whose marginal costs of generating electricity differed. The duration of such exchanges was usually one hour, during which time the purchasing utility had to maintain sufficient reserves of its own, given the interruptible nature of the transaction. Conversely, the wholesale rates for the sale of power to distributors with no generating capacity of their own or for firm power sales were derived directly from the cost of service.
The chief issues to be addressed in obtaining rate levels and structures for direct to user sales are discussed in the following two sections.

A1.1.4.1. Rate level

The rate level determined the extent to which revenues covered operating expenses, provided for a return on invested capital and were able to attract new funding. In practice, determining the cost of service was an extremely complex exercise, since a given level of revenues could be calculated in any number of ways. The most controversial aspects of this process were as follows (see (26) for instance):

- Use of actual current or estimated future values (fuel or capital costs for instance) to prevent rates from lagging behind real costs (regulatory lag), a problem that was intensified by the duration of the regulatory process.
- Establishment of a fair return on shareholder equity.
- Valuation of assets on the basis of their historic cost (usual practice in the USA), replacement cost or at a “fair value”.
- Inclusion or otherwise of the fixed assets in progress in the rate base.
- Accounting treatment for the deferred taxes generated when accelerated depreciation methods were applied.

A1.1.4.2. Rate structure

The rate structure determined the way that the cost of the overall service was distributed among different users. There were countless numbers of possible rate structures. The criteria traditionally followed when establishing rate structures are set out below:

- Simplicity, ready comprehension, public acceptability and practicality.
- Non-controversial interpretation.
- Provision of appropriate revenues.
- Revenue and rate stability over time.
- Equitable distribution of costs among users.
- Effective adjustment of the rate structure to the actual cost of providing each user with service, so rates guide consumers towards the economically optimum use of the existing resources, both as regards how much total energy is consumed and when it is consumed.

The traditional procedure for determining retail rates for electric power in the USA comprised the following steps (see 3, 11, 6, 7):

1. Type classification of users with similar supply requirements and similar contribution to total cost. Only a short number of types were defined, typically including domestic, commercial and industrial users. The latter were divided, in turn, into small- (typically commercial) and large- (typically industrial) scale users, street lighting, and government, railways and wholesale sales.
These categories could be further subdivided by supply voltage or other considerations, such as facility reliability (see section 3).

2. Breakdown of total service cost, which included both yearly system operating expenses and rate base costs, into four items: generation, transmission, distribution and tangible fixed assets, in accordance with very precise criteria (3, 6, 7). Only the costs related to these four items were broken down.

3. Breakdown of each of the above items into three categories: demand component (costs associated with installed capacity), energy component (costs associated with the amount of kWh produced) and customer component (costs associated with the number and type of users, irrespective of their consumption figures). Very precise criteria were also used for this breakdown.

4. Division of the sum found for each of the items described in the preceding paragraph among the different types of users. This could be readily calculated in the case of the customer component, in light of the definition of the term; the energy component was distributed among the various types of consumer in proportion to their respective consumption in kWh, although certain refinements, such as line loss for each type, were often accommodated as well. Several methods were proposed to distribute the demand component (3, 6, 7, 11), but none was regarded to be wholly satisfactory. In its Cost Allocation Manual, the National Association of Regulatory Utility Commissioners (NARUC) specified no single method to the exclusion of the others, although it did suggest that the coincident peak load method (see chapter 3) should be applied whenever possible. Reference (6) recommends a specific distribution method for each item.

5. Establishment of the rate structure for each type of user from the information obtained in the preceding steps. A compromise was sought between the objective of adapting rates to the actual cost structure and certain practical considerations such as the intrinsic limitations in metering and billing systems. Reference (50) gives a historic description of the different rate structures used in the USA. During the years studied here, the one most widely used for domestic consumers was the decreasing block structure, in which the price of each extra kWh decreased by steps as total consumption increased; this rate usually included a fixed monthly charge unrelated to consumption; the variable charge essentially covered the capacity and energy components. The rate used for commercial and industrial customers had separate energy (usually in the form of decreasing blocks) and demand (depending on the maximum demand used, as well as the load factor in some cases) components, in addition to the fixed user charge.

The traditional rate structure described above was widely criticised for not suitably reflecting the variations in the real price per kWh in different seasons of the year and/or times of day (6, 7, 39, 48). Some American electric utilities (6, 7, 25) had already modified their rate structures to take these variations into account, adding a further level of complexity to the above procedure.
A1.2. ELECTRIC POWER RATES: DETERMINING COST OF SERVICE

A1.2.1. Introduction

This section describes the procedure used by US electric utilities in the early nineteen eighties to determine the average cost of supplying electric energy, known as “cost of service”. The average cost of service was obtained by dividing the electric utility’s total costs by the amount of energy supplied. Total costs essentially included operating and maintenance costs, return on capital, depreciation and taxes. As indicated in section 1, the cost of service concept was only applied directly to energy sales that could be regarded to constitute the selling company’s own load, i.e., its direct sales to end users (or retail sales) and distributors with no or only token generating facilities of their own. Power supplied in other wholesale energy transactions and the related revenues were subtracted from the respective values of energy and total costs before computing the average cost of service. Cost of service constituted the grounds for determining the rate structures for both retail sales of electricity and sales to non-generating distributors.

American companies used the revenue requirements method for determining cost of service. This procedure is described in numerous papers, such as (34, 41, 33, 37). Countless variations arose, however, in the practical implementation of the method by electric utilities and regulatory commissions (see (26, 21)).

A1.2.2. The revenue requirements method

The core concept in the revenue requirements method is that cost of service must be such that it enables the company to recover all its costs as well as a fair return on its capital. The question of what exactly was understood to be a fair return was obviously intensely debated, and will be turned to later; see (33, 34) for an in-depth discussion of the issue.

In mathematical terms, revenue requirements (or total cost of service) can be expressed as follows:

TOTAL COST OF SERVICE=
= OPERATION AND MAINTENANCE COST +
+ DEPRECIATION + TAX +
+ RATE OF RETURN * RATE BASE -
- ADDITIONAL REVENUE

and the average cost of service is the quotient found by dividing the total cost of service by the power sales to which cost of service is applicable (as described above).

A succinct definition of the terms of the above equation follows. See the American standards on systems of accounts for electric utilities (20) for further details.

• Operating and maintenance costs: the cost of fuel, material and replacement parts, energy purchases, supervision, personnel and overhead.
• Depreciation: the linear method was generally used. Fixed assets in progress were not depreciated.

• Tax: all the taxes for which the utility was liable, i.e., on profit, revenue, property, social security and construction (except as owing to fixed assets in progress, since such tax was added into the value of the asset).

• Rate base: net fixed assets (plants, transmission and distribution facilities, other tangible and intangible fixed assets and nuclear fuel, less the cumulative depreciation for all of them), plus current assets (fuel and other material and replacement part inventory, advance payments and deferred revenue, research and development expenses and current asset requirements).

• Rate of return: average weighted interest rate on the company’s long-term financial resources (bonds, debentures, shares and preferred shares).

• Additional revenue: expenses/revenue deriving from the sale of the company’s property, revenue from wholesale energy sales and other revenue not directly related to the production of electric power.

A1.2.3. Discussion

The regulatory commission could question any of the sums presented by utilities when determining cost of service. If the commission decided that a given expense was excessive or unsubstantiated the respective amount was eliminated from the above equation.

The rate base was defined to encompass current assets and net fixed assets, with the latter accounting for the major share of the base. Net fixed assets were evaluated to be the sum of the non-depreciated property used for company operations. The treatment for net fixed assets varied widely from one regulatory commission to the next. The essential questions were: what should be included, when it should be included and at what value. In assessing fixed assets it was common practice to use the historic or original value, which was usually much lower than the current replacement value; certain regulatory commissions allowed utilities to use the replacement cost (computed from extrapolations based on the costs actually incurred), or a “fair” value, which each commission established at its discretion. One particularly controversial area was the inclusion or otherwise of fixed assets in progress in the rate base. When inclusion was not permitted, no provision was made for remuneration for the fixed assets in progress, and the utility was authorised to include the respective interest costs of the capital invested in the works in progress item. If all or part of the fixed assets in progress was included in the rate base, the interest on the part in question was not charged. The trend in the years discussed here was for a growing number of regulatory commissions to allow the inclusion of the fixed assets in progress, to avoid sudden hikes in the rate base, undue interest fund growth during construction and excessive haste in commissioning facilities. A number of different procedures was in use to appropriately account for variations in the rate base throughout the year.

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5 See the comment on standardised accounting below.
A peculiar American accounting practice known as standardised accounting lay at the root of another variation in the way the rate base was computed. This procedure consisted basically in keeping fictitious parallel accounts used exclusively to determine the company’s tax liability each year: instead of the usual linear depreciation used in the real accounts, these parallel accounts provided for accelerated depreciation to reduce taxes in the earlier years and increase the liability in subsequent years. This deferred tax accumulated in a fund. Most American electric utilities used standardised accounting. A thorough discussion of the effects of this practice on the determination of cost of service and the tax treatment can be found in (47).

One consideration of enormous practical importance for utilities in the reference period was the time that frequently lapsed between when a rate entered into force and when it was actually applied. This is what was known as “regulatory lag” in US terminology, and arose as the combined effect of two factors: the practice of calculating rates on the basis of the cost and energy sales figures prevailing when an application for a rate change was submitted, and the relatively long time lapsing between that date and when the regulatory commission’s resolution was forthcoming. The procedures in place to alleviate this problem included:

• Use of estimated values to cover the time expected to lapse before the new rates would come into effect. This practice was still uncommon at the time, however; regulatory commissions were much more prone to allow slightly higher rates to implicitly compensate for this shortfall (26).

• Clauses on automatic adjustment of rates to accommodate changes in fuel costs. Critics of this procedure sustained that it discouraged companies from seeking less expensive alternatives when fuel prices rose.

• Adjustment of the rate base as new facilities became operational.

The bone of contention in the ratemaking negotiations between electric utilities and regulatory commissions was the determination of the long-term rate of return on the company’s financial resources (bonds, debentures, preferred shares and shareholder equity: normal shares plus reserves). Given that the average interest rate on debt (bonds and debentures) and the average rate of dividends on preferred shares were in fact known in advance, the problem was merely a question of determining the rate of return on common equity. The general legislation in effect at the time provided that the rate of return on common equity should a) be comparable to that of other investments with similar risks and b) be sufficient to inspire confidence in the soundness of the company’s financial position so it could raise new capital when necessary. Much has been written about this important question in ratemaking: see (33, 34) for a detailed discussion and (2, 11) for a briefer review. In practice, regulatory commissions would set this rate after hearing the opinion of different experts and considering issues such as the method adopted to assess the fixed assets, the estimated lag between the period when rates were to be applied and when they were calculated, the inclusion or otherwise of fixed assets in progress and so on. The model used to quantify the cost of a utility’s own capital on the

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6 Supreme Court, Hope Natural Gas Case, 1944.
grounds of the risk associated with the various types of businesses is known as the Capital Asset Pricing Model (CAPM).

The method most commonly used in the period considered was WACC or Weighted Average Cost of Capital.
A1.3. ELECTRIC POWER RATES: STRUCTURE

A1.3.1. Introduction

Electric utilities can supply energy to other companies and/or directly to their customers. Both types of sales can be subdivided, in turn, into categories: end user or retail sales may be classed as domestic, commercial or industrial, depending on consumer characteristics, and wholesale or inter-utility energy exchanges as firm power, economic exchange or emergency sales, depending on the type of transaction involved. Rates were established for each of these categories under the supervision of the respective regulatory commission. This section describes American utility ratemaking procedures. The ground rule in this process was coverage of the total costs of supplying electric energy, calculated as described in the preceding section. The emphasis in the present section is on the methods for distributing these total company costs among the various power sales categories (users, distributors, inter-utility exchanges) and, as appropriate, among the various classes of users or customers (domestic, commercial, industrial and so on). Costs were broken down as far as necessary (into the three components - demand, energy and customers - on the basis of the voltage at which power was delivered, as well, perhaps, as by periods – peak, flat and off-peak -, depending on load levels) to obtain all the elements required to design the final structure for each type of rate. The criteria used in inter-utility energy exchanges are introduced in the following chapter.

As noted in section 1, the determination of rate structures from the average cost of supplying energy (cost of service) involves two essential tasks: the first, called cost allocation, consists in distributing each of the items comprising the total cost of service among the different categories of power sales (and classes of customers), and is described in section 3.2. The second is the final determination of the rate structure for each type of service, in keeping with the objectives set out in section 1.4.2, to formulate fair rates. Section 3.3 is devoted to this second task.

Generally speaking, American electric energy rates for each type of service or class of customer were uniformly structured; i.e., no distinction was made between peak and non-peak times. Rates were based on average embedded costs, which yielded a single price per kWh for the entire year, despite the fact that the cost of supplying electricity varies with the time of day and season of the year7. Authors critical of such traditional rates (39, 9, 48, for instance) sustained that prices that do not reflect the actual cost structure lead to an economically inefficient use of electricity. A number of American companies (see 25, 7, 8) had begun to adjust their rates to take account of such time-related variations in cost (marginal costs), while keeping average rates equal to average costs (a method is known as “peak load pricing”). In practice the outcome was the use of two separate schedules distinguishing between summer and winter or peak and non-peak periods. Under a purely marginalist approach, rates would have been established in accordance with actual marginal costs, and that in turn would have upset the balance between average rates and average costs.

7 This notwithstanding, the rate for each class of service was designed to ensure that it contributed proportionally to cover the cost of system peaks through the (explicit or otherwise) demand component of the rate.
The increasing importance attached in the USA to establishing rates that would reflect
the real differences in electric power costs at different times of day and/or seasons of the
year was addressed in Congress’s enactment of the Public Utilities Regulatory Policies Act
(PURPA) in 1978 and in several utilities’ business practices. In addition to introducing
the standard traditional approach, this section describes how costs were broken down and
rate structures formulated to reflect different demand conditions. This discussion is based
on literature reviewing the practices generally followed across most of the US electricity
industry (3, 6, 7, 8, 9, 11, 15).

A1.3.2. Cost allocation

The traditional procedure for assigning costs to types of services rested on three different
blocks of information: a) the company’s accounts, pursuant to the FERC uniform system
of accounts (20) to obtain the utility’s total cost of service broken down into the usual
items; b) the types of services among which costs were to be distributed, which might fall
under the jurisdiction of several different bodies (FERC, state regulatory commissions),
types of power sales (consumers, energy exchange) and types of customers; c) the
electricity system operating data needed to partition costs among the different types of
service; in particular, the contribution made by each type of service to total system
demand, along with certain characteristics of each type of service, load factor and demand
factor among them.

The discussion below describes the cost allocation methodology recommended by the
National Association of Regulatory Utility Commissioners, NARUC (3), which consisted
in the following: a) functional cost classification, b) cost classification by demand, energy
and customer components; c) allocation of customer, energy and demand costs to types of
service; d) allocation of total costs to types of service.

Functional cost allocation

Functional cost allocation involved consolidating the partial costs comprising the total
cost of service into a short list of items that could be associated with the chief functions of
electric power supply, namely, generation, transmission and distribution. This
classification facilitated subsequent cost allocation to the different types of service.

The generating function included all the costs associated with the generation or purchase
of electricity at power plant bars and the delivery of this energy at connection points with
neighbouring utilities. All costs associated with power transmission within the utility’s
system as well as to and from other companies were classified under transmission.
Distribution, in turn, covered all costs associated with the transfer of energy from the
transmission grid to consumers over the distribution grid, as appropriate (for certain
types of service and consumers, power was supplied directly from the transmission grid).

Certain costs not directly classifiable in any of the above three functions, such as
overhead, other tangible fixed assets, accounting and financial costs and so on were
classified by associating them with other more readily classifiable costs and processed
following the same method.

* Load factor: average demand in a given interval/maximum demand in the same interval.
The costs attributed to a given function might in turn be subdivided to facilitate their subsequent allocation to one type of service or another (dividing the grid into primary and secondary distribution, for instance).

**Cost classification into demand, energy and customer components**

In the next step in the final allocation of costs, the items resulting from the breakdown described in the preceding section were reclassified into the three components - demand load, energy consumption and number of customers - that represented quantifiable characteristics of each type of service.

The general classification criteria used were as follows: the demand component depended on the investment in facilities and therefore tended to remain constant in the short term, regardless of the amount of energy actually generated and/or transmitted in the system. The energy component tended to vary directly with the amount of power generated and/or transmitted. The customer component tended to vary with the number of customers serviced. Strictly speaking, this classification and the use subsequently made of it could only be justified if each group of total costs (demand, energy and customer) was assumed to vary linearly with the respective parameter (demand level, energy consumed and number of customers) and independently of the other two. But this was a mere approximation of what actually occurs. The evolution of economic theory in the interim has shown that such assumptions were mistaken.

Following these rules entailed including metering, billing and connection costs, plus a percentage of distribution costs (including capital costs and costs of maintaining a minimum distribution grid (3), in the customer component. The energy component included energy purchases, fuel and generating costs, maintenance costs - which varied with the amount of power generated/transmitted - and even the operating costs (including depreciation) that depended more on use than time. The demand component included the costs of capital and depreciation as well as the taxes associated with generating plants, transmission lines, substations and the part of the distribution grid not included in the customer component.

Again, a detailed description of the criteria underlying this classification may be found in reference (3). One subject of special interest was the determination of the customer cost component in connection, for instance, with the distribution grid, where no obvious way had been found to separate this component from the demand component.

**Allocation of demand, energy and customer costs to types of service**

Once the figures on total consumption by type of service and as a whole were found, the total energy costs could be readily allocated to each type of service (assuming that the price per kWh did not depend on the time of day or season of the year when energy was consumed).

Total customer costs were allocated to each type of service on the basis of the number of customers in each type of service, weighted by suitable correction factors to reflect customer differences by type of service (see 3, 6).

The allocation of total demand costs was the most controversial item in cost allocation due to the difficulty in finding a workable procedure that fittingly evaluated the
contribution of each type of service to system demand. The three most characteristic methods are defined briefly below: further information may be found in (3, 6,1 15). In the coincident peak load method costs were distributed among the types of service in proportion to their respective demand at annual system peak demand. NARUC (3) suggested this method wherever it could be feasibly applied: average monthly peak demand values had to be used for systems that peaked more than once a year.

In the non-coincident (or more accurately, not necessarily coincident) peak load method, costs were partitioned in proportion to annual peak demand for each type of service. This method yielded stable distribution coefficients and could be implemented with cheaper metering equipment than required in the preceding scheme; this was the procedure of choice in the USA. It met with many an objection, however, for ignoring the effect of coincident use on demand (3, 15). In a third method, the average and excess demand method, allocation was based on proportionally distributing only the costs incurred to meet the average demand for each type of user. All other costs were distributed in accordance with the second method and in proportion to the difference between the peak and average demand for each type of service.

Regardless of the method employed to allocate demand costs, the demand values used had to be referred to a single reference point on the grid. Consequently, considerations such as voltage and line loss had also to be factored into the equation (3).

Allocation of total costs to types of service

The total costs allocated to each type of service, regulatory jurisdiction and, as appropriate, class of customers, was obtained from the results found as described in the preceding section.

A1.3.3. Establishing rate structures

While NARUC and other institutions attempted to standardise cost allocation, it seems that there were no guidelines for establishing specific rate structures.

Nonetheless, the cost itemisation described in the preceding section provided a rationale for establishing one rate structure for each type of customer based on the three cost components - demand, energy and customer -, where the unit costs of each component were obtained by dividing the total yearly costs by yearly peak load (kWh), energy supplied yearly (kWh) and number of customers, respectively. Naturally, provision had to be made for the demand factor for the class of customer in question to apply the unit cost of demand. Such a correction could be made (11) because there is a known empirical relationship between the load factor (which can be measured) and the demand factor: the product of peak demand times the demand factor was billed at the unit cost of demand. The total cost of demand was found to be more conveniently expressed in terms of the individual customer's load factor. The result was approximately comparable to a load rate schedule in which costs decrease depending on the load factor (11).

The above rate structure was ill-suited to residential customers, since it would call for individual meters able to record peak demand. Domestic demand was sufficiently even and stable for the other demand characteristics to be deduced from the total energy consumed. In other words, the demand and energy components of cost could be treated
jointly as a fictitious “power” component. The result was the typical declining block rate for domestic users (11).
A1.4. ELECTRICITY RATES: WHOLESALE POWER SALES

A1.4.1. Introduction

This section describes the different types of inter-utility power sales then in use in the USA, along with the criteria most widely used by companies to establish the respective rates. It also summarises the formalities and procedures that utilities followed to obtain FERC approval of these rates.

As discussed in section 1, wholesale energy transactions were divided into two major groups: sales to distributors, primarily municipal government-owned utilities and cooperatives; and co-ordination sales among electric utilities, most of which took place in the context of power pools. The rates for sales to distributors were established in the same way as retail rates, since such sales formed a part of the seller’s own load. The rates for co-ordination services ranged from long-term firm power sale rates, which included all a company’s fixed costs, to economic energy exchanges, which took account of incremental variable costs only.

Reference (5) provides an interesting description of co-ordination transactions among electric utilities in the USA, and reference (41) an account of the procedures for applying for approval of wholesale rates. All of these issues are discussed below.

A1.4.2. Classification of wholesale sales

Wholesale sales were divided, firstly, into sales to distributors and energy co-ordination transactions. Sales to distributors formed a part of the seller’s own load, although they could on occasion be assigned lower priority; nonetheless, utilities were required to keep sufficient reserves for such sales and make provision for possible growth when planning their generating and transmission systems. In co-ordination sales account was taken of variations respecting supply reliability, transaction timing, buyer’s and seller’s reasons for undertaking the transaction and, naturally, the rates for each service. The rest of this section is devoted to such co-ordination services.

The FERC (4) classified co-ordination sales as follows:

- Long-, medium- and short-term firm power.
- Generating unit capacity.
- System capacity.
- Diversity interchanges.
- Reserves.
- Maintenance.
- Emergency.
- Financial transactions.
- Conservation of fuel.
Annex 1. Case example of traditional regulation of the electric power sector

- Firm transmission.
- Non-firm transmission.
- Run-of-the-river.
- Hydroelectric storage.
- Hydroelectric system co-ordination.

Many of these transactions were associated with the establishment of power pools. Firm power purchases were usually concluded to offset buyer energy shortfalls and inability to meet the obligations inherent in pool membership.

The following is a description of the types of services provided under each of the above items.

**Firm power**

Under firm power contracts the seller committed to supplying a certain amount of energy during the period specified in the contract. The seller had to maintain the necessary reserves, since this service could only be interrupted under narrowly restricted conditions. Depending on the duration, these agreements were divided into long-term — over one year—, medium term —from one month to one year—, and short term —from one day to one week— energy sales.

**Generating unit capacity**

This consisted in the provision of capacity service and the associated energy from a specific generating unit owned by the seller. It granted a contractual right over part of the production of a given unit, but with no share in its ownership. The reliability of this service was contingent upon the availability of the unit specified in the contract.

**System capacity**

This consisted in a given amount of capacity (without reserves) and/or energy, which was to be supplied, under contract, by the seller's system as a whole or a specific group of generating units. Reliability was higher than under generating unit power arrangements, but lower than in firm power agreements.

**Diversity interchange**

Capacity and/or energy interchanges between systems whose demands peaked at different times or whose operating costs and/or generating availability were timed differently. These were reciprocal agreements with firm power commitments; therefore the supplier had to take the necessary measures to ensure availability at the times programmed for interchanges.

**Reserves**

These were agreements to share the reserves established, explicitly in pools and explicitly or implicitly in other contexts.
**Maintenance**

Capacity and/or energy supplied to a system to supplement its reserves during programmed maintenance. The terms of such agreements were specific to each contract and services were typically co-ordinated 6 to 12 months in advance, under firm power sales arrangements.

**Emergency**

The energy supplied to a system to counter a sudden and unexpected power shortfall. Contracts for such services often contained clauses that established reserve levels for each system, since these services were reciprocal. The duration ranged from 24 to 72 hours, after which, if the system experiencing difficulties was still unable to meet demand, service could be continued or otherwise at the seller’s discretion. In the event, sales were reclassified as short-term firm power.

**Economy transactions**

Unconditionally interruptible power supplied for a given period, usually one hour, in which the seller's incremental costs were lower than the buyer's. The latter had to maintain sufficient reserves, given the interruptible nature of the service.

**Conservation of fuel**

Energy supplied to refrain from utilising units whose fuel was subject to government-mandated supply constraints. The purpose was to solve a material problem, such as a fuel shortage, not a financial one such as increases in fuel prices.

**Transmission services**

These services were provided at one of three levels of reliability.

- Firm: non-interruptible, except where system security was at stake.
- Conditionally interruptible: interruptible only under the conditions specified in the contract.
- Unconditionally interruptible: interruptible at the discretion of the utility providing the service.

Wheeling services were and are transmission services provided by a company that neither generates nor consumes the energy sold.

**Run-of-the-river**

Sales of energy generated by hydroelectric systems in which water cannot be stored.

**Hydroelectric storage**

Energy interchange agreements that enabled a company with hydroelectric plants to buy energy to store water in reservoirs at times when energy prices were low and run their turbines at times when they rose.
Hydroelectric and conventional steam co-ordination agreements

Agreements under which a steam generation system received surplus hydroelectric power from another system. Energy was fictitiously “stored” in the sense that the hydroelectric system received an equivalent amount of energy at a later time, the next day for instance.

The classification of transactions by type to determine the rate applicable as described in the following section were negotiated by the companies involved prior to application to the FERC for rate approval.

A1.4.3. Wholesale rates

As noted in the introduction, the rates for the sale of power to distributors were computed in the same way as retail rates, following the criteria set out in section 3.

Co-ordination sales typically comprised three elements: a demand component, an energy component and a surcharge on the latter.

The demand component was found in firm power, conditionally interruptible (system energy, maintenance and conservation of fuel) and generating unit power sales. The rationale for this component was the need to recover the seller’s fixed costs (capital costs, depreciation, taxes and fixed maintenance costs) for providing these services.

This component could be readily calculated for generating unit power sales as the yearly fixed cost of the unit, weighted by its availability.

For long-term firm power sales the demand component was calculated with the system average fixed cost method i.e. by dividing the utility’s yearly generating and transmission system fixed costs by system peak load. The underlying assumption was that the service was provided by all the seller’s generating units.

For the rest of the services that included the demand component in the rate (medium- and short-term firm power, system energy, maintenance and conservation of fuel), the scheme most commonly used was to determine the share in the weighted average cost of capital. Under these arrangements the demand component was calculated by multiplying the annual fixed unit costs of the generating units that it was assumed would supply the service, times the number of kilowatts expected to be generated for these services. Under this method the assumption was that energy would be supplied from certain “marginal” units, since these services had lower priority than the seller’s own load, and therefore would be provided with less efficient generating units which normally had lower fixed but higher variable costs. The ultimate outcome of this method was a smaller demand component but a larger energy component than would be found for long-term firm power services.

The maintenance services addressed here that included the demand component in the respective rates were services provided outside pools. Inside such pools, as explained below in section 5, the agreements governing such services were designed, among other things, to co-ordinate maintenance programming for each of the systems forming the pool; the rate applicable to the demand and energy supplied while each utility’s
generating equipment was undergoing maintenance varied depending on whether or not such maintenance was programmed in keeping with pool objectives.

The energy component was present in all co-ordination sales and its purpose was to cover the variable costs incurred by the seller to provide the service. Fuel accounted for the bulk of these variable costs and dispatching and administrative costs for the rest. Plant start-up and maintenance costs had also to be included in the energy component in some cases.

The basis for calculating this component was normally the seller’s incremental costs, defined by the FERC to be the “costs that would not have been incurred but for the transaction” (5).

Surcharges were also to be found in all co-ordination sales, and were added to the incremental costs in the energy component. Utilities used three types of surcharges: fixed, percentage and “share in savings”.

The “share in savings” surcharge was only present in financial transactions. Its purpose, to provide an incentive for such transactions, was completely different from the purpose of percentage and fixed charges, namely to attempt to recover the seller’s incremental costs, which were difficult, not to say impossible, to quantify (5).

The share in savings surcharge was calculated as the average difference between the seller’s and buyer’s incremental costs.

Percentage surcharges met with widespread opposition because it was believed that the costs generated did not grow at the same pace as the cost of fuel, which constituted the bulk of incremental costs. The FERC subsequently imposed ceilings on percentage surcharges for transmission and conservation of fuel services.

Transmission costs, in turn, were generally included in the overall rate for wholesale service. The method used to calculate these costs is given below:

\[
\text{Firm transmission (}/$/\text{kW}) = \frac{\text{Total transmission system costs}}{\text{Peak load}}
\]

\[
\text{Conditionally interruptible transmission (}/$/\text{kW}) = \frac{\text{Total transmission system costs}}{\text{Interconnection line capacity} \times \text{Transmission system capacity}}
\]

\[
\text{Unconditionally interruptible transmission (}/$/\text{kWh}) = \frac{\text{Total transmission system costs} \times \text{Overhead}}{8760 \times \text{Peak load}}
\]

Finally, there was no standard rate for hydroelectric storage and hydroelectric system co-ordination services, which depended, rather, on individual agreements and was usually calculated from established formulas.

A1.4.4. Application for approval of wholesale rates

Rates for new services or modifications of existing rates were subject to FERC approval. Utilities applied for such approval between 120 and 160 days in advance of the date
scheduled for the service to begin. This could give rise to two different situations: 1) claims or objections on the part of stakeholders (purchasing companies, states where the utilities were located, and so on), which were lodged more often than not when sales to distributors were involved; and 2), no objections were raised, which was usually the case in connection with co-ordination sales. When claims were filed a hearing was held in which all the parties involved had to submit proof to substantiate their positions. The final decision was made by the FERC. When no claims were filed the commission studied the applications and granted or denied approval based solely on the documents submitted by the seller.

The documentation that the seller had to submit with the application was classified into four groups:

1. General:
   Scheduled date for implementation of service, sales agreements established, reasons to change or create the rate, customers affected.

2. Effects of the rate:
   Comparison among past transactions and those envisaged under the new rate schedule, and comparisons with other schedules for similar services.

3. Accounting and cost of service information.
   Cost data and other factors explaining the rate requested.

4. Rate structure
   The volume of documentation required for modifications was much more extensive than for creating a new service, but the commission tended to regard all applications as modifications. There were two procedures for applying for modifications: full and abridged.

Rate applications for co-ordination sales usually took the abridged route, since these services had been negotiated in advance and an agreement already reached on the rate; all the FERC actually did in such cases was to give its consent to these agreements.
A1.5. POWER POOLS

A1.5.1. Introduction

A power pool may be defined to be a group of two or more utilities that co-ordinate their operation and planning to minimise operating costs, save on fuel and increase the reliability of the electricity system. Such pools were common in the USA in the nineteen eighties, when there were around 30. They held a substantial share in the American system, accounting for 38% of the total electricity generated in the country (43).

In order to materialise the benefits of membership in a power pool, utilities established procedures and fostered action that provided for: an equitable distribution of participants’ obligations and benefits, shared use of the transmission grid and plants, co-ordinated operation of the power pool and establishment of the prices for energy transactions.

The creation and/or operation of power pools often entailed trade-offs for member utilities in the form of the loss of company independence inherent in pool membership. The obligation incumbent upon pool members to co-operate might also clash with their competitive positions (generally in terms of wholesale energy sold to third parties). Consequently, it was up to each utility to weigh these drawbacks against the advantages of greater co-ordination with other pool members.

The types of agreements in place in pools across the USA varied from informal inter-utility arrangements to formal agreements among all the companies in a group, as well as bilateral and multilateral agreements. The first type required no legal approval. Bilateral and multilateral agreements involved wholesale energy sales and were subject to approval by the Federal Energy Regulatory Commission (FERC), which regulated energy exchanges, transmission rights and energy payments. Finally, member companies might also conclude formal agreements that governed the operation of the pool as a whole and each member’s responsibilities. These agreements were also subject to FERC jurisdiction. The relationship between each individual utility and the regulatory commission in its respective state was not affected by membership in a power pool. Therefore, the rates for the sale of electric energy to each utility’s customers were established in keeping with the criteria described earlier in this document. As far as electricity rates were concerned, then, the presence of power pools added a new and fairly complex framework for negotiating inter-utility wholesale transactions to the scenario described above.

In short, a power pool should be viewed as a series of electric utilities with separate rates for their customers (in all respects: relationships with the respective state regulatory commissions, rate levels and structures, and so on) that derived mutual benefit from co-ordinating their operation and planning activities9. A list of the possible benefits that such co-ordination should afford (17) in a pool with a maximum degree of integration would include:

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9 Power pools were created to co-ordinate utility operation and thereby benefit from the savings generated by exchanging energy and sharing reserves. Co-ordinated planning was introduced at a later stage, if at all.
(Shared) saving of operating costs through energy transactions for financial reasons. Savings were maximised when the pool was operated as a single company from the same control centre (with or without satellite facilities in each company).

- Reduction of each company’s operating reserves, spinning or otherwise, since the reserves required to deal with contingencies could be shared.

- Benefits deriving from joint operation to exploit the differences in individual companies’ load curves (the use of hydroelectric power, for instance).

- More effective response to emergency situations, for co-ordinated handling of such incidents.

- Co-ordinated maintenance programming to minimise the costs of substituting for plants being serviced.

- Lower long-term margin of reserve capacity, increased transmission grid reliability and economies of scale in new facility construction, thanks to better co-ordinated planning across several utilities.

This section begins with a brief description of pool member rights and obligations with regard to the use and maintenance of suitable joint generating and transmission capacity (section 5.2). This is followed by a discussion of the aspects to be considered when co-ordinating operation and planning (section 5.3). Finally, a few remarks are devoted to the way prices were established for energy transactions among pool members.

This section has drawn heavily from reference (43). Other references used include (4, 17, 19, 40, 42).

Because of the enormous diversity in the degree of integration in US power pools in and around the nineteen eighties, this section is limited to a discussion of the major issues and general procedures adopted. The specific solutions to each of these issues found by four pools with very different levels of integration can be found in reference (43).

A1.5.2. Ownership and use of facilities: rights and obligations

Pool membership rights and obligations in connection with facility ownership and use were concerned, on the one hand, with the use of the transmission grid and, on the other, with generating plants and their production in terms of pool needs. Certain aspects of the agreements reached in these areas were subject to FERC review for approval and/or recommendations.

Agreements on the use of the transmission grid could include questions ranging from maintenance specifications, plans for optimum growth and each member’s responsibility in the construction of its portion of the grid, to the mere review by a pool committee of each participant’s transmission grid planning and cost estimates and their impact on the reliability of the grid as a whole. Member access rights to use the grid for short- and long-term energy exchanges were also defined. In this regard, any of the types of exchanges defined in the preceding section could be the object of such agreements.

The establishment of agreements on the short- and long-term use of the transmission grid was essential to satisfactory pool operation. Short-term conditions were set up in
such a way as to guarantee the co-ordinated conducting of pool activities. Long-term grid use rights were defined prior to concluding contracts for firm power sales, shared plant ownership, wheeling and others. One particularly relevant consideration in this context is that when one utility granted another the use of its transmission grid, its own competitive position on the wholesale energy market might be adversely affected. Grid construction, in turn, might prove to be more advantageous for the pool as a whole than the utility concerned. In such cases, compensation or incentives were established so no single company was unduly jeopardised.

Plant-related agreements were reached in the context of a joint capacity expansion plan for the pool, which co-existed with each member’s entitlement to implement its own plan to carry its own load, which was merely reviewed by a pool planning committee. Where a joint expansion plan was adopted, it addressed issues such as pool growth forecasts, reliability criteria and planning models that would ensure that overall demand could be met to such criteria.

The right to access the energy produced by plants was defined for both short- and long-term horizons. The transactions cited above would be conducted in the short term and would be open to all pool members. At the same time, arrangements were made for outages in the event of power shortfalls. Solutions might range from sharing the outage to requiring the member with a power shortage to reduce its load by the amount of the shortfall. Long-term planning involved establishing criteria for each member’s share in plant construction and its access to the joint transmission grid.

A1.5.3. Co-ordinating operation and planning

A1.5.3.1. Co-ordinating operation

Short-term co-ordination among pool members reduced fuel and production costs. Long-term co-ordination allowed for the efficient expansion of pool capacity in terms of the use of capital and energy. System operation-related issues included energy exchanges, reserves, maintenance programming, emergency procedures and hourly dispatching. All these issues are discussed below.

Economic energy transactions

Energy exchanges between utilities with different marginal generating costs were conducted under bilateral agreements with or without a broker or central dispatching, depending on how deeply integrated the pool was.

Bilateral inter-utility agreements facilitated forward plant programming, to save fuel oil, for instance, by using coal-fired or nuclear energy. The transaction price was reached by a method mutually agreed to by the parties and approved by the FERC. Since these exchanges could be terminated when the seller’s load increased, the buyer had to have as much energy in reserve as it bought. Such arrangements, therefore, enabled buyers to reduce load but not to shut down plants. Agreements of this nature were readily negotiated and billing was similarly straightforward. They called for no sophisticated control or communications equipment, nor did they entail any loss of autonomy for the parties concerned. The drawback was that it took a fairly large number of such
arrangements for all pool members to participate and optimise the benefits of energy exchanges.

Brokering was and is a means for exchanging information that provided all utilities with hour-by-hour energy prices. Energy transactions were conducted in an orderly manner, beginning with the most divergent prices. The broker’s role was performed either manually or automatically, i.e., via computer, and ranged from merely displaying prices and facilitating agreements to defining the exchanges each company should conclude for the following year on the grounds of dispatching information. Brokering had relatively low implementation costs and allowed each company to essentially conserve its power of decision. Moreover, the benefits deriving from each transaction were easy to evaluate. It had the same disadvantage as the preceding scheme, however: it would take many bilateral agreements for all pool members to reap all the possible benefits and it could not guarantee optimal operation.

Under central dispatching all the generating plants in the pool were operated as if they formed a part of a single system, to minimise total operating costs. This arrangement was implemented in accordance with the well-known principle of optimum load dispatching: evening off the incremental production costs of plants in operation, after adjusting for line losses.

As a rule, centralised dispatching of all pool plants led to different results than if each company’s plants had been dispatched separately. The method for calculating the benefits of economic energy transactions within the pool was based on this difference between the results attained under the two approaches (centralised and individual), which exactly determined the benefits to be derived from all manner of exchanges between pool members. This procedure, which is more complex than the two methods discussed above, was necessary in a context in which pairs of buyers and sellers could not be easily identified. In power pools with centralised dispatching, the comparative analysis of centralised (or actual) and individual (or calculated) dispatching was useful to identify and classify inter-utility exchanges by types (economic transaction, reserves, maintenance, and so on) for the intents and purposes of applying the respective rates (see section 5.4). Under individual dispatching arrangements, firm power purchases and shares in plants were regarded to form a part of a company’s self-generation.

Of the three types of energy exchanges discussed, centralised dispatching was the one requiring the most sophisticated control and communications equipment and involving the most complex billing processes and greatest loss of utility autonomy. The advantage was that the benefits generated by energy exchanges were greater under these circumstances, although dispatching investment and operating costs, along with the higher costs deriving from greater administrative complexity, were deducted from such benefits. In other words, investing in a central dispatching facility was only justified where the sum of such costs was smaller than the increase in benefits.

**Reserves**

For the intents and purposes of operation, a distinction is drawn between spinning (grid-synchronised) and non-spinning (not synchronised with the grid) reserves. The aim of sharing reserves was to reduce the amount of both types of reserves while maintaining the same degree of system security as if the reserves were the exclusive responsibility of
each utility. This was the objective regardless of the criterion adopted for establishing reserve capacity requirements.

In pools without centralised dispatching, each company was allocated a share in the total pool reserves in proportion to its maximum demand load. In pools with centralised dispatching, reserves were programmed in accordance with overall criteria of economy and security, regardless of specific plant ownership. The reserves to be contributed by each company were determined by comparing the real results with the (fictitious) results that could have been expected if individual company dispatching arrangements had been in place, as noted above.

**Maintenance programming**

Another possible area for co-ordination was plant maintenance programming. Appropriate programming would prevent energy reserves from dropping to critical levels when loads peaked. Programming usually covered periods of from two to five years to take account of nuclear fuel load and supra-annual rainfall cycles, although frequent revisions were required to convert obligatory into programmed outages, as well as changes in facility availability.

One of the most difficult tasks in joint maintenance programming was to persuade pool members to agree to it. Financial incentives could be used to compensate companies that were obligated to overhaul their plants when it was most cost-effective for the group, but not for them, to do so.

**Emergency procedures**

These procedures included action such as interrupting supply, lowering frequency and reducing voltage. Co-ordinating these measures maximised reliability and minimised the effects of contingencies. Pursuant to NAPSIC (North American Power Systems Interconnection Committee) guidelines, each pool had to establish its own internal rules of procedure and assign each utility specific responsibilities. In highly integrated pools, supply outages were shared.

**Hourly plant programming**

Plant start-up and shut-down could be programmed by each utility or by the pool. Any pool with both centralised programming and centralised dispatching was in fact operated as if it were a single system. These arrangements, which minimised operating costs, also entailed a greater loss of individual utility independence and control over its own system. Financial compensation was arbitrated for companies connecting plants to the grid above and beyond their own needs to meet pool requirements.

**A1.5.3.2. Co-ordinated planning**

Pool utility rights and obligations with regard to the ownership and use of production facilities (plants and grid) were discussed in section 5.2. Here this issue is addressed from the specific standpoint of planning. It was only in highly integrated pools that members acquired specific planning obligations. In less closely-knit pools such obligations were limited to submitting individual plans to a pool committee for the information of other members.
As far as plants were concerned, joint planning helped pool members attempt to attain an optimal generating structure. In the more tightly integrated pools, joint installed capacity needs were determined in accordance with load predictions and established reliability criteria and then divided among members in accordance with their maximum demand loads and the shape of their load curves. Consequently, each member was obligated to have sufficient installed capacity to satisfy its load curve and its proportional part of the reserves. In the event of energy shortages, the pool member concerned had to conclude firm power agreements or purchase a share in a plant or otherwise pay a penalty for each kW it was short. Such installed capacity responsibilities were reviewed periodically to take account of variations in demand, both utility-by-utility and overall.

Companies could plan to build plants or lines that were of no interest to the pool, but only the ones identified to be of joint interest were eligible for pool benefits. Utilities could, and at times were required to, offer other members part of the capacity and energy deriving from the latter types of plants to other members under short- or long-term agreements. Short-term arrangements made it possible to meet a member’s power needs or cover shortages before the next review of capacity responsibilities. Under long-term contracts, usually for the life of the plant, the buyer acquired part of the plant’s capacity.

A1.5.4. Establishing prices for energy exchanges and the use of the transmission grid

As noted above, membership in a power pool had no impact on a utility’s relationship with state regulatory commissions for the intents and purposes of ratemaking, or with the FERC in connection with the regulation of energy exchanges with non-pool companies. Moreover, for many of the transactions between pool members (the ones not affected by co-ordinated pool operation in areas such as firm power exchanges, system capacity and so on), the provisions cited in section 4 on wholesale energy sale characteristics and rates continued to be fully applicable. Power pools, however, were affected by two circumstances that need to be addressed, expanding on the discussion in section 4.

1. New types of transactions tended to arise in power pools due to their closely co-ordinated memberships. Examples would be reserve exchanges and energy transactions in the event of forced or programmed maintenance outages.

2. In highly integrated power pools, and in particular where centralised dispatching was in place, it was not possible to identify inter-utility transactions \textit{a priori} to ascertain what type they were or even if they existed at all; in light of this, the ratemaking criteria set out in section 4 could not be applied.

This section deals primarily with the analysis of these two situations. In any event, a series of principles was established for ratemaking in power pools: the pool identified the transactions that generated profits and costs and designed methods to calculate and distribute both fairly and effectively. Prices were calculated to cover the cost of all transactions, ensure the greatest possible savings and provide for a fair distribution of costs and profits among pool members. The more tightly integrated the pool, the greater was the complexity it faced in establishing equitable prices.
For the intents and purposes of establishing prices, internal pool transactions were classified into one of the following three types: Energy transactions, capacity transactions, grid use transactions.

**Energy transactions**

This category covered the economic energy transactions described in section 4, which were further subdivided into different categories to establish prices: economic transactions *per se*, and transactions for programmed outages, forced outages and capacity shortfalls. In power pools with no centralised dispatching these transactions could be readily identified. Where arrangements called for centralised dispatching, the procedure described above was used: i.e., *a posteriori* comparison of real programming to calculated individual dispatching.

Economic transactions were operations simply designed to take advantage of the differences in the buyer’s and the seller’s incremental costs. The other three categories of economic transactions were intended to accommodate special circumstances. In programmed or forced outage transactions, energy was exchanged while one of the buyer’s plants, which would have otherwise been used, was out of service due to pool-programmed maintenance or forced unavailability, respectively. In capacity shortfall transactions, the buyer experienced a power shortage (installed capacity plus capacity purchases from other plants plus firm energy purchases) and was unable to cover its own load plus its pool-allocated reserves.

In all these cases the price of the service exchanged was determined by the respective companies’ incremental costs. Pools with centralised dispatching applied the costs deriving from the calculation of individual dispatching. This generated a savings fund, since buyers paid more than sellers received. The balance in the fund was subsequently distributed according to pre-established criteria, such as each company’s proportional share in strictly economic transactions.

**Capacity transactions**

These transactions were typically concluded when one utility needed capacity (and not necessarily energy) from another to honour its capacity obligations to the pool, in other words, its own maximum load plus allocated reserves. This situation might overlap with the energy transaction, in which case the respective costs were summed. Several categories could be distinguished: for reserves, programmed outages, forced outages and capacity shortages. The last three were discussed above. Reserve transactions, in turn, were sought by utilities that found that their reserve quotas could be more economically covered by another utility’s plant.

The prices for these transactions were, once again, obtained on the basis of the incremental costs incurred by the parties concerned as a result of the transaction. It should be noted that in the case in point these incremental costs did not include the energy component (already taken into account when valuing energy transactions), but only the component associated with the capacity transaction. For instance, in a reserve transaction which enabled the buyer to refrain from connecting a plant that would only have been used to meet the reserve quota requirement, the price would reflect the costs saved in plant start-up, operation under technical minimum conditions and shut-down.
One controversial issue was the establishment of the maximum amount of time that a forced outage could be regarded to be just that, and not a capacity shortage. This sort of situations arose when a plant experienced very long-term forced unavailability. The price of forced outage transactions was usually kept higher than incremental costs as an incentive for utilities to maintain high availability.

A utility with a capacity shortage had to pay a penalty, which typically was very nearly the capital costs of the least expensive plant that could be bought to meet the company’s capacity needs. Before reaching such a situation, utilities would buy firm power or capacity from other utilities under the usual terms described in section 4.

Grid use transactions

As far as the transmission grid was concerned, prices reflected the use of one utility’s grid by another. There was no single method for establishing the price for this service, due to the difficulty involved in fairly and effectively compensating a company for the use of its grid.

Prices could be established on the grounds of losses or could be standardised where short-term energy exchanges prevailed. When standardised prices were adopted, it was up to the pool to decide which exchanges were covered and which were not.
A1.6. SUMMARY AND DISCUSSION

This Annex has presented the most salient features of electricity ratemaking in the USA in the early nineteen eighties. One outstanding characteristic of electricity ratemaking in the United States in the nineteen eighties was the enormous diversity of procedures in place, the outcome of the changes introduced since the industry first began to be regulated by state commissions. New York and Wisconsin created theirs in 1907 and the Federal Power Act of 1920 created the Federal Power Commission, now known as the FERC. Nonetheless, despite all this diversity, the overall structure remained relatively stable over time and was largely shared by systems across the country.

This review would be incomplete, however, without at least a brief discussion of the criticism levelled at various aspects of the traditional American approach to electricity ratemaking and the main changes proposed. This section is devoted to such a discussion. A more detailed treatment of these issues can be found in references (4, 6, 9, 25, 26, 27, 28, 32, 39, 44, 48, 49, 50), which are only briefly summarised in the paragraphs below.

A1.6.1. Discussion

Globally speaking, and judging by the indirect results, it may be sustained that the American electricity ratemaking system worked satisfactorily for a relatively long time (49): unnecessary duplication was avoided, the cost of electricity was comparatively low, the quality of service was excellent, capital investment was suitably remunerated and clearly unfair discrimination in rate structures was avoided.

Moreover, the traditional regulatory framework provided for regulatory stability. The guarantee that costs would be recovered generated a climate that favoured investment, reduced capital costs and provided for high security of supply. In addition, provision was made for meeting “social obligations” such as special rates for disadvantaged communities of users, R&D activities, protection of autochthonous fuel, diversification of energy sources and environmental protection.

However, in the late nineteen seventies, criticism of and/or proposals for modifying many of the aspects of traditional US electricity ratemaking began to be advanced. The most significant of these are discussed below.

As noted on several occasions in this unit, one particularly striking aspect of American ratemaking was the variety of regulatory bodies involved in the process, which could give rise to the application of very different procedures even within one and the same utility (operating across several state lines, for instance). This led on occasion to paradoxical situations: a certain utility operating in the state of Massachusetts, for instance, unbundled into a generation and transmission company on the one hand and a number of mere distributors on the other, a structure that qualified it for FERC regulation and enabled it to avoid (particularly strict) state rules. In Texas, on the contrary, where the regulatory commission was more prone to favour electric utilities, all the state’s electric companies physically disconnected from the rest of the American system to completely avoid FERC jurisdiction. Numerous attempts have been made, generally sponsored by the FERC, the Department of Energy or the National Association of Regulatory Utility Commissioners, to establish more uniform criteria and methods.
Although traditional regulation was based on the recovery of cost of service, under the American regulatory mechanism new rates were often approved considerably after they had been designed (regulatory lag). This lag represented no problem whatsoever for the utilities in an environment of declining electricity prices, such as in the late nineteen seventies. From then on, however, under pressure of a number of factors - including the high cost of money, legal difficulties to build new plants and lines, rising fuel prices and costs in general – price trends reversed. In this new scenario, regulatory lag suddenly became relevant, since the rate of return on capital calculated using last year’s costs was insufficient for the current year. The problem was not, then, intrinsic in the revenue requirements approach, which should in fact be regarded more as a systematised method to determine cost of service than an original procedure. It was, rather, a problem of the practical implementation of the method. Several solutions were proposed (49, 26, 4), the most prominent of which included reducing the time required to process applications for rate changes and using estimated future costs to calculate cost of service.

From the nineteen eighties to date, change in traditional regulation has been driven by a series of considerations of a critical nature. Perhaps the aspect most frequently criticised was the very philosophy on which cost of service and rate structure were based. Economic theory sustains that rates are most economically efficient when they equal the marginal cost of operating the electricity system. Rates based on embedded costs were lower than marginal costs, since they included old plants built very inexpensively. Together with the development of marginalist theory to determine rates, further thought was given to rate structures that would send the right signals to customers (39, 50, 6, 15, 26). The outcome of these developments has been hourly rates, whose implementation was facilitated by the evolution of computer and communications technology.

Real time pricing schemes have now been implemented in a number of electricity systems around the world, which are based on real short-term marginal costs at any given time. In a traditional environment, these would naturally have had to be completed with revenue conciliation methods to reach the true cost of service.

Another frontal attack on traditional regulation came with the advent, first, of renewable energies and co-generation or CHP facilities as “external” generators under the incentives provided for in the PURPA act (qualifying facilities). This later gave way to BOO (build-operate-own) and BOT (build-operate-transfer) arrangements, which in turn broke the ground for the appearance of Independent Power Producers or IPPs. The need to handle transactions with all these new players on the field, together with the on-going development of power pool transactions, brought changes in the way inter-utility rates were determined, with a tendency to form liberalised organised market places that fuelled competition between companies.

The problems posed by traditional regulation with respect to risk management and investment incentives also contributed to development along these lines. Traditional cost-of-service frameworks encourage overinvestment, with consumers shouldering all the risks. Liberalisation has evened the score somewhat, by passing at least part of the risk on to the generating business.
A1.7. REFERENCES


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