**Proposed amendment A2.8**

In order for EAPL's access arrangement for the MSP to be approved the WACC estimates and associated parameters must be amended to more accurately reflect current market conditions. In particular, the post-tax nominal return on equity should be set at 13.0 per cent, the pre-tax real WACC should be set at 7.0 per cent and the associated inflation assumption set at 2.9 per cent.

## 2.6 Non-capital costs

### 2.6.1 Code requirements

The Code (sections 8.36 and 8.37) allows for recovery of the operating, maintenance and other non-capital costs that would be incurred by a prudent service provider acting efficiently.

Attachment A to the Code (see Appendix B to this *Draft **Decision)*** requires the disclosure in the Access Arrangement Information of costs (including wages and salaries, rental equipment, gas used in operations, materials and supply, corporate overheads and marketing) with some disaggregation by zones, services or categories of assets, unless it would be unduly harmful to the legitimate business interests of the service provider, user or prospective user.

### 2.6.2 EAPL's proposal

The various components of EAPL's forecast non-capital costs for the initial access arrangement period are shown in Table 2.18 and a summary of the various items comprising each category is contained in Box 2.1

**Table 2.18: Forecast non-capital costs, 2001 to 2005 (July 2000 $'000)**

| Year ending 30 June | 2001 | | 2002 | | 2003 | | 2004 | | 2005 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $'000 | Yo | $'000 | Yo | $'000 | Yo | $'000 | Yo | $'000 | Yo |
| Labour | 5393 | 44 | 5 546 | 42 | 5699 | 46 | 5783 | 42 | 5 868 | 47 |
| General administration | 3249 | 26 | 3265 | 25 | 3280 | 26 | 3297 | 24 | 3313 | 27 |
| Materials | 1285 | 10 | 2202 | 17 | 1180 | 10 | 2369 | 17 | 1059 | 9 |
| Communications systems | 1163 | 9 | 1168 | 9 | 1175 | 9 | 1180 | 9 | 1186 | 10 |
| Gas used | 900 | 7 | 797 | 6 | 799 | 6 | 727 | 5 | 730 | 6 |
| Licences | 189 | 2 | 184 | 1 | 185 | 1 | 185 | 1 | 187 | 2 |
| Return on working capital | 85 | 1 | 92 | 1 | 86 | 1 | 95 | 1 | 86 | 1 |
| Total | 12264 | 100 | 13255 | 100 | 12406 | 100 | 13636 | 100 | 12430 | 100 |

Source: EAPL access arrangement information, p. 41.
Note: Some of the column totals may not add up due to rounding.

## Box 2.1: Summary of EAPL's operating and maintenance cost components

**Labour**

Includes the wages, salaries and on costs of 91 full time staff and the costs of contract labour. The number of full time employees is predicted to rise to 93 by the end of the initial access arrangement period in response to the additional workload associated with third party access (for example, processing customer nominations, marketing activities).

**General Administration**

Includes administrative and audit fees, cost of insurance, advertising expenses, aircraft expenses, bank charges, cleaning, communications (other than system lease costs) and computing costs.

**Materials**

Comprises ongoing maintenance directly associated with the transmission of gas. Also included are provisions for the following major works:

- $0.25 million repairs to compressor unit in 2000/01;
- $1.2 million major overhaul of compressor unit in 20001/02; and
- $1.2 million major overhaul of compressor unit in 2003/04.

**Communications System**

Annual operating lease expenditure on Telstra's communication network.

**Gas used**

Mainly gas used **as** compressor fuel.

**Pipeline licence fees**

Fees imposed by the governments of New South Wales, South Australia, Queensland and the ACT.

**Working capital**

EAPL has included a nominal return of 11.1 per cent on working capital.

Source: Access arrangement information, pp. 38-42.

EAPL states that its costs are low in comparison with available benchmarks and represent the efficient costs of operating the MSP. According to EAPL this level of efficiency has been achieved by a cost reduction program implemented over recent years. Since EAPL purchased the pipeline in 1994 costs have been reduced from $9.94 per kilometre in 1994 to $6.28 per kilometre in 1998, while full-time equivalent staff numbers have fallen from 125 to 92 over the same period.

EAPL has compared its operating costs with those of other Australian companies (as shown in Table 2.19) and concluded that its costs compare favourably with other pipelines. EAPL also provided other key performance indicators in support of its proposed operating costs. (See Chapter 4 of this ***Draft Decision.)***

### Table 2.19: Operating costs comparisons (1999$)

| | EAPL | Epic | AGLP | TPA | TPA | Alinta Gas | Pipeline Authority | PASA |
|---|---|---|---|---|---|---|---|---|
| State | NSW | SA | NSW | VIC | VIC | WA | NSW | SA |
| Year | 2001 | 1999 | 99/00 | 1999 | 95/96 | 95/96 | 64/95 | 94/95 |
| $m/1000 km | 6.06 | 7.34 | 2.8 | 11.0-16.0 | 9.9 | 13.6 | 10.4 | 10.1 |

*Working capital*

With respect to working capital EAPL considers that it is appropriate to apply a nominal rate of return to its working capital rather than a real rate. In support of its argument EAPL notes that the value of working capital is eroded over time by inflation. EAPL is proposing a nominal rate of return of 11.1 per cent, which is consistent with its proposed real pre-tax WACC of 8.4 per cent. EAPL has calculated its working capital requirements at 23 days, which it argues is less that the rule of thumb of 45 days adopted by many regulatory authorities in the USA.

*Gas used*

Following EAPL's submission of its proposed access arrangement, APT has informed the Commission that its fuel gas purchase contract has expired. APT considers that a more standard and equitable approach would be for shippers to provide their own fuel gas at the receipt point. APT has requested that this issue be raised for discussion in this ***Draft Decision***.[115]

### 2.6.3 Submissions by interested parties

While no submissions suggested that EAPL's proposed non-capital costs are too high, nor offered alternative lower costs, Innovative Energy Australia (on behalf of Incitec) is critical of direct comparisons of operating costs among Australian pipelines because of different levels of compression and the associated costs. Innovative Energy Australia raises two issues:

- since the MSP has only two compressors installed its operating costs are likely to be lower than other pipelines with a greater degree of compression; and
- even if the degree of compression were comparable, distortions would still arise because of differences in the cost of gas used in compression, which is a major operating cost.[116]

Innovative Energy Australia also states that the data presented in Table 2.19:

> illustrates the benefits of privatisation and the relationship between operating costs with the amount of compression on a pipeline, but little about the performance of EAPL vis-à-vis world's best practice![117]

### 2.6.4 Commission's considerations

The Code requires the regulator to allow only the prudent costs (and not necessarily actual costs) of a service provider acting efficiently and in accordance with accepted and good industry practice to achieve the lowest sustainable cost of delivering the reference services. The efficiency gains made by EAPL since its acquisition of the MSP are acknowledged and shown in Figure 2.2. Figure 2.2 compares actual O&M costs on a dollar per metre basis from 1993 to 1998, which includes the years leading

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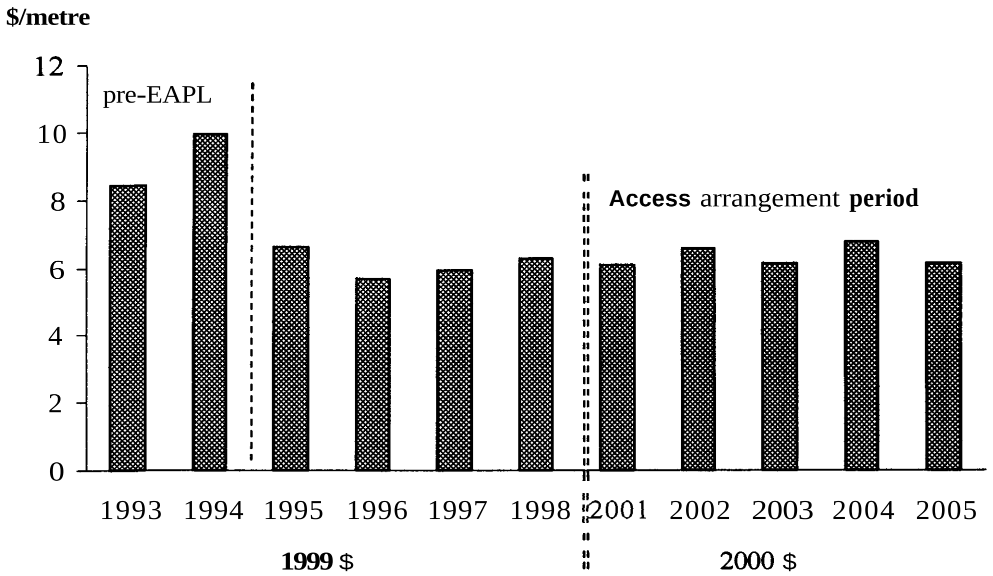
115 APT letter to the Commission, 21 September 2000, p. 4.

116 Report prepared by Innovative Energy Australia Pty Ltd on behalf of Incitec, July 1999, p. 4. Submitted by Incitec 18 August 1999.

117 Report prepared by Innovative Energy Australia Pty Ltd on behalf of Incitec, July 1999, p. 4. Submitted by Incitec 18 August 1999.

up to EAPL's acquisition of the MSP, with forecast costs over the access arrangement period.

**Figure 2.2: Operating and maintenance costs ($ per metre)**




EAPL has not included a productivity factor during the initial access arrangement period. Table 2.20 shows the percentage change in non-capital costs during this period. The annual percentage change in real terms for each year is shown together with the change for the five-year period. In order to better illustrate trends, the costs of major works have been excluded from the 'Materials' cost item.

**Table 2.20: Percentage change in non-capital costs, 2001 to 2005**

| | 2001-2002 Yo change | 2002-2003 Yo change | 2003-2004 Yo change | 2004-2005 Yo change | 2001-2005 % change |
|---|---|---|---|---|---|
| Labour | 2.8 | 2.8 | 1.5 | 1.5 | 8.8 |
| Gen admin | 0.5 | 0.5 | 0.5 | 0.5 | 2.0 |
| Materials | -3.2 | 17.8 | -0.9 | -9.4 | 2.3 |
| Communications | 0.4 | 0.6 | 0.4 | 0.5 | 2.0 |
| Gas used | -11.4 | 0.3 | -9.0 | 0.4 | -18.9 |
| Licences | -2.6 | 0.5 | 0.0 | 1.1 | -1.1 |
| Working capital | 8.2 | -6.5 | 10.5 | -9.5 | 1.2 |
| Total | 0.3 | 2.9 | 0.3 | -0.1 | 3.5 |

Source: ACCC derived from EAPL's access arrangement information, pp. 41-42.

Some costs, such as gas used, vary in accordance with volumes. Table **2.20** shows that total non-capital costs are forecast to increase by about 3.5 per cent in real terms over the five years of the access arrangement period, with the major contributor being a forecast **8.8** per cent increase in labour costs.

In support of its proposed operating costs EAPL has provided key performance indicators suggesting that the operating costs of the MSP compare favourably with other transmission pipeline systems. Criticism of EAPL's analysis by Innovative Energy Australia highlights the limitations of benchmarking and inter-company comparisons.

Operating and maintenance costs are usually in the order of one to two per cent per annum of capital costs (excluding compressors), while maintenance costs for compressors are usually in the order of three to six per cent per annum of capital costs.[118] Based on ORC, EAPL's total O&M costs are about 1.3 per cent of capital costs. On the basis of the information available to it, the Commission's view is that EAPL's O&M costs are reasonable.

EAPL submitted its forecast non-capital costs prior to AGL floating its gas transmission assets on 13 June 2000. This restructuring of AGL's gas transmission assets may have an impact on the non-capital costs of the MSP. Any consequent difference in costs may be considered part of EAPL's incentive mechanism, so that EAPL would retain the profit if the difference is in its favour or wear the loss if the restructuring results in higher costs. The Commission has not attempted to assess the likely impact on EAPL's non-capital costs as a result of the restructuring, but rather has assessed the reasonableness of EAPL's forecast non-capital costs as contained in its assess arrangement information.

***Cost of materials***

Included in EAPL's costs of materials are two items for $1.2 million in 2000/01 and 2003/04 for major overhaul of compressors. It may be more appropriate for costs of improvements of this nature to be added to the asset value of the compressors and depreciated over the remaining life of the compressors, rather than expensed in the year that the expenditure occurs. It is the Commission's understanding that it is EAPL's accounting practice to expense these items in the period that the costs are incurred. The Commission does not consider that capitalising these costs, rather than expensing them, is likely to have a significant impact on tariffs. Accordingly, the Commission is inclined to accept EAPL's proposed treatment of these costs.

***Working capital***

The Commission notes EAPL's proposal to include in its operating costs an allowance for a return on working capital. A US authority quoted by EAPL defined working capital as follows:

> **… the average amount of capital provided by investors … over and above the investment in plant … required to bridge the gap between the time that expenditures are required to provide service and the time collections are received for that service.**[119]

The Commission proposes not to allow EAPL an explicit return on working capital. The rationale for this approach relates to the methodology adopted by the Commission

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[118] **AGA, *Gas Transmission Pipelines Development and Economics*, Research Paper** No. **8, February** 1998, **p.** 37.

[119] **Ohio** PUC, ***Re Columbus Southern Power Co*,** 1992 133 **PUR4th** 525, 550, **cited by EAPL in Access arrangement information, p. 28.**

for its modelling of cash flows. Rather than model the timing of EAPL's cash flows throughout the year, the Commission has assumed in its model that all costs and revenue are incurred on the last day of each year. In reality, EAPL's cash flows would occur at regular intervals throughout the year, giving EAPL a benefit above the regulated revenue equal to the time value of money on the net cash flow received throughout the year. The Commission considers that this benefit more than compensates EAPL for any gap between payments and collections during the year.

**Proposed amendment *A2.9***

> In order for EAPL's access arrangement for the MSP to be approved, an allowance for a return on working capital should not be included in EAPL's revenue requirements.

***Gas used***

The Commission notes APT's proposal that shippers should supply their own fuel gas and invites interested parties to comment on this proposal. If this proposal is adopted, the non-capital costs of the MSP would have to be reduced accordingly by removing the costs of fuel gas. The Commission estimates that the effect on tariffs by the removal of these costs would be a reduction of less than one cent per PJ (about 0.7 cents/PJ).

## 2.7 Forecast revenue

### 2.7.1 Code requirements

Three alternative methodologies are set out in section 8.4 of the Code for determining total revenue: cost of service; internal rate of return; and NPV. The Code also allows for other methodologies to be used providing the resulting total revenue can be expressed in terms of one of the three methodologies. If a cost of service approach is adopted total revenue should be the sum of the rate of return, depreciation and operating, maintenance and other non-capital costs.

The Code (section 8.6) recognises that, in view of the manner in which various parameters such as the rate of return, initial capital base, depreciation schedule and non capital costs may be determined, it is feasible that a range of values may be attributed to total revenue. For example, the difference in the value of the initial capital base as proposed by EAPL and that proposed by the Commission has a significant impact on total revenue. Accordingly, the Code allows the regulator to take into account any financial and operational performance indicators it considers relevant to determine the level of costs within the range of feasible outcomes that is most consistent with the objectives contained in section 8.1 of the Code.

### 2.7.2 EAPL's proposal

Essentially EAPL is proposing a 'cost of service' approach (based on forecast costs) to determine its target revenue stream over the access arrangement period.[120] The relevant costs are:

- return on assets;
- depreciation; and
- operating, maintenance and other non-capital costs.

Assessment of each of these individual components is undertaken earlier in this chapter. To calculate its annual return on assets, EAPL applies its pre-tax real WACC to the average assets for each year of the access arrangement period. Table **2.21** shows the relative contribution to total revenue of each of these three cost components.

**Table 2.21: Components of proposed total revenue (July 2000 $m)**

| | 2001 | | 2002 | | 2003 | | 2004 | | 2005 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $m | % | $m | % | $m | % | $m | % | $m | % |
| Return on assets | 55.16 | 60 | 53.43 | 59 | 52.09 | 58 | 50.81 | 57 | 48.93 | 57 |
| Depreciation | 24.03 | 26 | 24.13 | 27 | 24.67 | 28 | 25.03 | 28 | 25.12 | 29 |
| Non-capital costs | 12.26 | 13 | 13.26 | 15 | 12.41 | 14 | 13.64 | 15 | 12.43 | 14 |
| Total | 91.45 | 100 | 90.82 | 100 | 89.17 | 100 | 89.48 | 100 | 86.48 | 100 |

Note: Some totals may not add up due to rounding.

To create a smooth price path, EAPL is proposing that tariffs in each year after the initial year should vary by the formula CPI-X. Consequently, forecast revenue, in terms of tariffs multiplied by volumes, will differ slightly to the target revenue determined by the cost of service approach. However, to ensure no under or over recovery of revenue occurs, the 'X' factor is set so that the NPV of the two revenue streams is identical. This is illustrated in Table **2.22.**

**Table 2.22: Target and forecast revenue (July 2000 $m)**

| Year ending 30 June | 2001 | 2002 | 2003 | 2004 | 2005 | NPV |
|---|---|---|---|---|---|---|
| Target revenue | 91.45 | 90.81 | 89.17 | 89.48 | 86.48 | 354.23 |
| Forecast revenue | 95.54 | 87.33 | 88.84 | 86.06 | 89.36 | 354.23 |

[120] EAPL's proposal is consistent with the cost of service approach described in section **8.4** and the price path approach described in section 8.3(a). References to cost of service approach in this Draft Decision will be in terms of the section **8.4** definition rather than that contained in section 8.3(b).

### 2.7.3 Submissions by interested parties

Certain interested parties commented on aspects of the components which constitute EAPL's target revenue, such as the rate of return and value of the initial capital base. No objection was raised to the overall approach, such as the use of CPI-X as a mechanism to ensure a smooth price path over the access arrangement period.

### 2.7.4 Commission's considerations

The Commission notes that a smooth price path has the beneficial property of avoiding unnecessary price shocks to users during the access arrangement period. It is not opposed in principle to the substitution of the target revenue stream with a forecast revenue stream of the same (or less) NPV. However, as noted in earlier sections, the Commission considers that EAPL's revenue requirements are overstated. As indicated in Table 2.23, adoption of the proposals in this ***Draft Decision*** in relation to the cost components of the MSP would reduce the target revenue on average by about 34 per cent per annum compared with that proposed by EAPL.

**Table 2.23: Comparison of total revenue proposals (July 2000 %m)**

| Year ending 30 June | 2001 ($m) | 2002 ($m) | 2003 ($m) | 2004 ($m) | 2005 ($m) |
|---|---|---|---|---|---|
| Total revenue – EAPL | 91.45 | 90.81 | 89.17 | 89.48 | 86.48 |
| Total revenue – ACCC | 59.31 | 59.87 | 58.34 | 60.19 | 58.96 |
| Difference (%) | 35 | 34 | 35 | 33 | 32 |

## 2.8 Forecast volumes

### 2.8.1 Code requirements

The Code permits the calculation of total revenue (section 8.4) and the calculation of reference tariffs (sections 8.38 to 8.41) to be based upon forecast volumes. Further, section 8.2(e) of the Code requires that any forecasts required in setting the reference tariff represent best estimates arrived at on a reasonable basis.

### 2.8.2 EAPL's proposal

Table 2.24 presents EAPL's forecast of total annual volumes of gas demand in NSW (and ACT) over the period from 1999 to 2014, together with total forecast volumes to be transported by EAPL. The proposed initial access arrangement period is from 2001 to 2005. For comparison purposes, Duke Energy's forecast of total demand is also included.

The methodology used by EAPL to derive the forecast volumes is based on a composite of forecasts and inputs from several sources, including industry reports, confidential information from customers, market surveys, econometric studies, AGA, ABARE and NEMMCO. However, EAPL states that AGA and ABARE studies are somewhat dated and overstate the short to medium term demand, in particular demand in the power generation sector. **As an** example, EAPL states that these forecasts overestimated the 1999 demand by more than 20 PJ.

**Table 2.24: Forecast volumes of gas (PJ) by destination and source, 1999-2014**

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2008 | 2010 | 2012 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **NSW** demand **(EAPL)** | 111.8 | 109.6 | 109.4 | 113.3 | 117.4 | 124.1 | 138.9 | 159.1 | 179.7 | 196.4 | 204.2 | 211.2 |
| **NSW** demand (Duke) | | 105.1 | 110.0 | 115.0 | 120.0 | 130.0 | 141.0 | 148.1 | 159.4 | 174.1 | 190.2 | 196.3 |
| Deliveries ex Moomba into NSW/ACT/ VIC | 117.7 | 117.2 | 97.4 | 86.8 | 87.4 | 79.9 | 80.9 | 98.1 | 108.7 | 123.4 | 147.2 | 175.2 |
| Interconnect deliveries into NSW/ACT | 0.0 | 0.0 | 2.0 | 3.0 | 4.0 | 10.0 | 17.0 | 20.0 | 22.0 | 24.0 | 23.0 | 23.0 |
| Total quantity. transported by **EAPL** | 117.7 | 117.2 | 99.4 | 89.8 | 91.4 | 89.9 | 97.9 | 118.1 | 130.7 | 147.4 | 170.2 | 198.2 |

Sources: Access arrangement information, p. 13, Supplementary access arrangement information p. 2, and information supplied by EAPL to the Commission.
Duke Energy, *Submission to ACCC for Development of an Undertaking for Access to the Eastern Gas Pipeline,* 15 November 1999, p. 5.

Note: Figures for 1999 are actuals.

EAPL outlines a number of assumptions and factors it considers will have an impact on the volume of gas transported through the MSP in each of the years between 2001 and 2005. The assumptions underlying the forecast volumes are:[121]

- the EGP was expected to commence operation with an initial load of 20 PJ per annum increasing to 60 PJ per annum within several years. This represents about 20-50 per cent of the NSW and **ACT** demand currently supplied exclusively by EAPL. EAPL's forecast load takes into account EAPL's lower share of NSW demand as a result of the entry of the EGP;
- due to considerable excess electricity generation capacity available in NSW and Victoria, and consequent low prices for electricity, gas fuelled power generation from new plant is not expected to become competitive until at least 2005. Total demand for major new power generation and cogeneration facilities is projected to increase from 7 PJ in 2005 to 50 PJ by 2014;
- smaller (0.5 to 20 MW) embedded generation and cogeneration plants are expected to take up to **3** PJ per annum by 2005;
- the ALISE project's start up will be delayed until late 2005 when it will access about 10.5 PJ per annum from Moomba;[122]

[121] EAPL's Access Arrangement Information, pp. 12-15 and supplementary access arrangement infomation, 28 October 1999, pp. 2-10.

[122] The ALISE project is a large cogeneration project that is proposed to be located in Botany, Sydney, serving a number of companies.

- in the industrial sector, new opportunities will emerge in the minerals processing, heavy industry and other industrial applications such that load will grow from 5 PJ in 2003-04 to 10 PJ in 2006;
- strong growth is forecast in the tariff market (residential and small commercial) but this is more than offset by a slowdown in industry gas demand and a lack of new energy intensive industry. This results in static demand in NSW between 1997 and 2002;
- the tariff and contract market sectors in NSW and ACT traditionally served by AGL will grow by one per cent per annum after 2002;
- the Cooper/Eromanga Basin producers are projected to sell up to 12 PJ per annum into the Victorian market by 2005 as a competitive response to a loss of market share in NSW;
- new retailers in NSW and Victoria are expected to enter into the competitive market with an impact on the northbound Interconnect demands;
- the Interconnect pipeline extension transporting gas into and out of Victoria will have contractual and physical bi-directional flow capability as EAPL will be serving markets in both States. Northward flow through the Interconnect into NSW is expected to be low in early years as a result of the EGP; and
- Moomba will be an important gas supply hub in the longer term to bring Papua New Guinea (PNG) and Timor Sea gas into south-eastem Australia as the Cooper Basin and Bass Strait fields are depleted.

EAPL states that it is facing a complex and unique market environment over the next few years and that it will compete in three markets (NSW, ACT and Victoria) served by three transportation routes (the MSP, EGP and the Interconnect). As a result, it considers that there is a high degree of uncertainty attached to demand forecasts, including end-user demand, pipeline competition and inter-basin competition.[123]

EAPL's forecasts in the main are based on, or consistent with, ABARE's forecasts, with one notable exception concerning the timing of the forecast increase in demand for gas for power generation and cogeneration. EAPL claims that ABARE's forecasts include a steep increase in demand for gas in NSW for power generation and cogeneration in the period between 2001 and 2004, whereas the current consensus view is that this will take place some years later. Another difference between EAPL's and ABARE's estimates is that ABARE's projections start from an estimated level for 1998-99 that was higher than the actual level reached.[124]

For the residential market, EAPL is forecasting moderate to steady growth from 19.9 PJ in 2001 to 24.1 PJ in 2014, which is the same forecast produced by ABARE. EAPL states that competition from electricity has limited the market penetration in this sector and will continue to do so in the foreseeable future. Moreover, EAPL sees limited scope for major network extensions, which would be confined to growth corridors and some regional towns.[125]

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123 Supplementary access arrangement information, p. 4.
124 Supplementary access arrangement information, p. 3.
125 Supplementary access arrangement information, p. 4.

For the commercial and industrial sectors, EAPL is forecasting static demand between 2001 and 2002, followed by one per cent growth in 2003 and then 1.5 per cent a year until 2014. EAPL lists a number of factors affecting growth in this sector, including: the maturity of the market; decline in manufacturing; slowness of industry to embrace energy conservation; post-Olympics and post-GST slump in building activity; competition from electricity; increased overall demand due to the entry of new marketers of gas; and the expected start-up of two or three new major industrial projects.[126]

According to EAPL, growth in demand for gas in New South Wales is 'largely a function of the installation of major gas-fired power generation and cogeneration capacity'.[127] It identifies a number of major power generation and cogeneration projects, in particular, the ALISE cogeneration project and the Kurnell gas-fired generation plant, which it expects will not begin operation until after 2005, due to excess capacity **and** current low electricity prices.

### 2.8.3 Submissions by interested parties

Santos notes that EAPL is forecasting substantial reductions in gas deliveries from Moomba into NSW, ACT and Victoria, from 115.8 PJ[128] in 1999 to 80.9 PJ in 2005, a decrease of 30 per cent. It argues that it is in the interests of pipeline owner to understate the volumes to be transported and overstate the losses in market share in order to keep tariffs high. However, it considers that a higher transportation tariff exacerbates the risk of market share loss and thus the assumption about volume loss becomes self full-filling or circular, such that lower volumes cause higher tariffs which, in turn, cause lower volumes. Further, Santos contends that EAPL's forecast of loss of volumes must assume certain tariffs for EGP. According to Santos, it would be 'an irony' if, by assuming low EGP tariffs, EAPL could forecast volume loss through its pipeline and thus justify a higher tariff. In Santos' opinion such an outcome does not reflect a competitive market.[129]

### 2.8.4 Commission's considerations

Forecast demand on the MSP is critical to the determination of EAPL's reference tariffs. The Code requires that forecasts represent best estimates. The reference tariffs have been calculated to deliver the total required revenue on the basis of the forecast annual volumes of gas transported. Any additional **gas** transported will lead to a higher revenue. Conversely, less revenue will be earned if actual volumes are below those forecast.

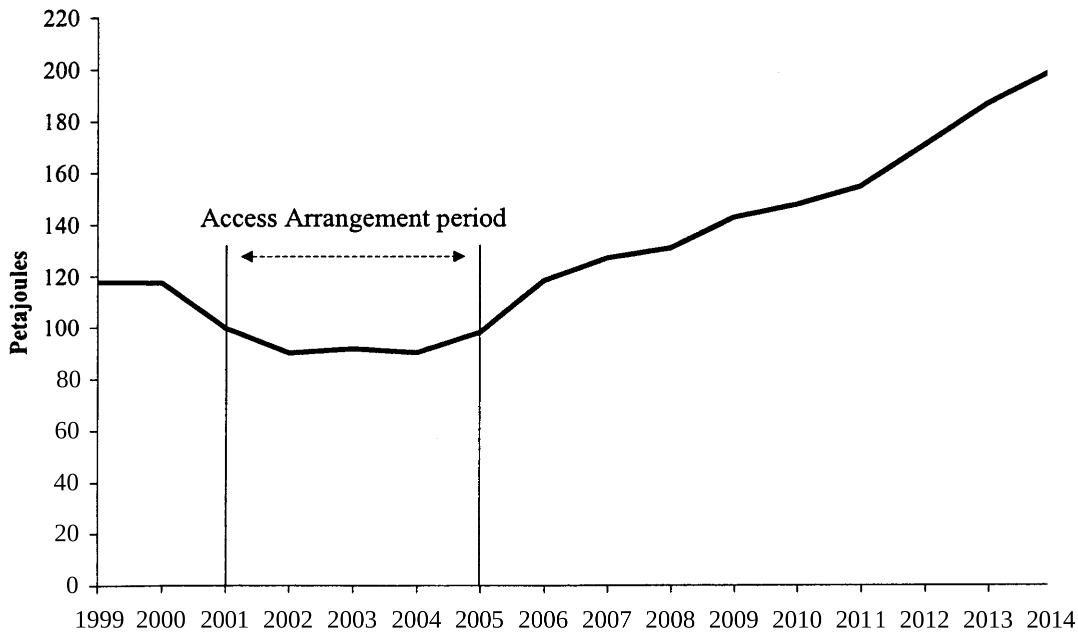
#### *Forecast volumes and the impact of the Eastern Gas Pipeline*

EAPL has factored into its forecast volumes a loss of market share to the EGP. EAPL's volumes are forecast to fall initially, then return to their current levels during the first

[126] Supplementary access arrangement information, pp. **4-5.**
[127] Supplementary access arrangement information, p. 2.
[128] 115.8 PJ was the estimate for 1999 provided by EAPL in its access arrangement information. p. 13. The actual figure was 117.7 PJ.
[129] Santos submissions, 29 July 1999 and 23 December 1999.

year of the next access arrangement period, before continuing to rise as the total market grows over time. This is illustrated graphically in Figure **2.3.**

**Figure 2.3: EAPL's volume forecasts, 1999 to 2014**




Source: Access arrangement information p. 13 and information supplied by EAPL to the Commission.
Note: 1999 figures are actuals.

Since EAPL's proposed tariffs are determined by dividing its revenue requirements by its forecast volumes, the forecast loss of market share to the EGP would lead to higher tariffs on the MSP than would otherwise be the case. In the absence of the EGP, EAPL's volume forecasts would be higher and its proposed tariffs lower. In other words, the entry of a new player would lead to higher tariffs, which is contrary to the outcome expected in a competitive market.

This raises the issue of the appropriate level of volumes to be used for tariff-setting purposes under these circumstances. Essentially the issue is who should bear the costs of the loss of market share, the service provider or users, or whether there should be some sharing of the costs. It could be argued that EAPL should have anticipated the introduction of alternative supply when it purchased the MSP. The expected loss of market share would reflect the commercial risk in a competitive environment and EAPL would be expected to bear any loss. Conversely, it could be argued that construction of the EGP was outside EAPL's control and that EAPL should not be disadvantaged because of it.

NERA was engaged by the Commission to report on regulation of pipelines which face a loss of market share to a new entrant.[130] NERA evaluated five scenarios for the regulation of tariffs within this context:

- basing tariffs on the service provider's expected market share (forecast volumes);

[130] NERA, Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC, October 2000.

- deeming volumes at current levels (prior to the loss of market share) for tariff-setting purposes;
- basing tariffs on defined (full) capacity;
- adopting a back-end loaded depreciation profile; and
- no regulation of tariffs.

In considering each of these options, NERA considered the following issues:

- which party (service provider or users) bears the costs of spare capacity;
- what incentives are implied for the service provider and users to grow the market and reduce spare capacity; and
- which party is in the best position to act on those incentives.

The issue of back-end loaded depreciation is considered elsewhere in this ***Draft Decision*** (section 2.4.4). The last scenario noted above (no regulation of tariffs) is not relevant to the current assessment as the MSP is a covered pipeline pursuant to section 1.13 of the Code.

The first three options can be considered a continuum, with deemed volumes (for example, at the levels expected in the absence of loss of market share to the new entrant) somewhere between forecast volumes and defined capacity. This continuum is illustrated below, with a brief summary of NERA's comments on each option.

High tariffs → Low tariffs

| *Forecast volumes* | *Deemed volumes* | *Defined capacity* |
|---|---|---|
| Users bear costs of spare capacity | Users and the service provider share the costs of spare capacity. | The service provider bears the cost of spare capacity. |
| Weak incentives for the service provider to grow the market. Strong incentives for users to grow the market. | Both have incentives to grow the market. | Strong incentives for the service provider to grow the market. |
| The service provider is best placed to grow the market. | The service provider is best placed to grow the market. | The service provider is best placed to grow the market. |

NERA’s preferred option is for tariffs to be set on the basis of defined capacity, irrespective of the level of actual volumes. NERA argues that the approach which should be adopted is the one that best aligns incentives and the ability to act on those incentives. NERA further argues that the service provider, in this case EAPL, rather than users is best placed to grow the market and improve utilisation of the pipeline. Therefore, it is the service provider that should bear the cost of the spare capacity, as this provides the service provider with the strongest incentive to grow the market. In NERA's opinion, basing tariffs on the level of defined (full) capacity provides the best alignment of incentives and ability to act. According to NERA this approach also provides the best incentives for future investment.

NERA rejects forecast volumes as the basis of setting tariffs. In this case users bear the full cost of excess capacity and therefore the service provider has only weak incentives to improve utilisation of the pipeline. Although under this scenario users have the incentive to improve utilisation of the pipeline, they are not in the best position to do so. NERA also rejects any deeming of volumes between forecast volumes and defined capacity for similar reasons. That is, users would bear some of the costs of excess capacity. Moreover, NERA argues that this scenario creates increased regulatory risk because of the uncertainty surrounding future treatment of volumes.

It is important to note that basing tariffs on defined capacity would have implications for all pipelines with spare capacity, not merely pipelines, such as the MSP, facing a new transmission supply source. In the case of the MSP access arrangement, EAPL would bear the cost not only of the loss of market share to EGP, but also of any spare capacity in the absence of market share loss.

NERA has advised the Commission that the normal regulatory practice adopted in the USA is to set tariffs on the basis of defined capacity, and that this approach does not appear to deter new investment.

Basing tariffs on defined capacity has some appeal to the Commission as it would overcome the apparent anomaly of tariffs rising as a result of the entry of **a** new player. Adoption of a deemed volumes or defined capacity approach in Australia, however, would represent a departure from the current approach adopted by regulators. Accordingly, the Commission is currently of the view that tariffs for the MSP should be based on forecast volumes. As other proposals in this ***Draft Decision*** would reduce overall tariffs to below current published levels, adoption of this approach would not result in a tariff shock to users.

Although the Commission does not propose to adopt the approach advocated by NERA, the Commission invites comments on the NERA report and its recommendations.

The Commission notes the concerns of Santos about the level of EAPL's proposed tariff associated with the forecast of gas quantities to be hauled. It also notes that reference tariffs establish a ceiling and that users may be able to negotiate tariffs below that level. The existence of substantial spare capacity in the supply of gas to NSW since the commissioning of the EGP might be expected to lead to some reductions in price by EAPL.

*Forecast NSW and **ACT** gas demand*

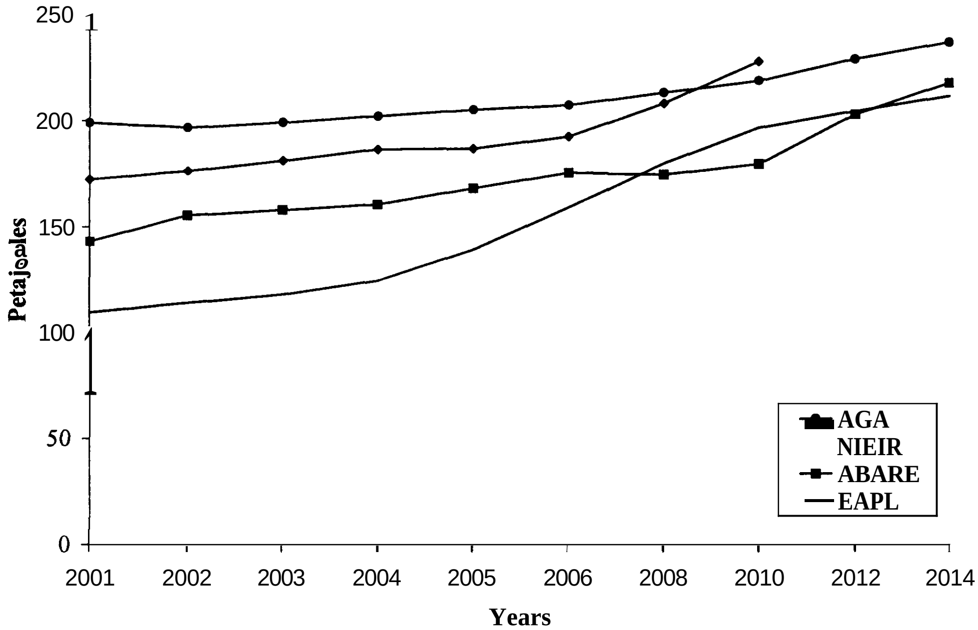
In assessing the reasonableness of EAPL's forecast volumes of **gas** demand for NSW and ACT over the initial access arrangement period the Commission has reviewed studies by ABARE, AGA, and National Institute of Economic and Industry Research (NIEIR) on behalf of the NSW Department of Energy (DOE).[131] A comparison of these forecasts is presented in Figure **2.4.** The Commission has also considered whether the methodology and assumptions underlying EAPL's forecasts are sound, taking into account key variables affecting the demand for gas, such as the level of economic activity and relative prices.

Some caution is required in comparing EAPL's forecasts with those of ABARE, AGA and NIEIR because of differing timing and methodology. For example, the ABARE's

[131] The Department of Energy is now known as the Ministry of Utilities and Energy.

forecasts are based on a fuel and electricity survey conducted in 1997 whereas, according to EAPL, its forecasts incorporate updated and current market information. In addition, the Commission understands that EAPL's natural gas demand forecasts exclude the supply of ethane in NSW whereas it is normally included in other studies.[132] Nonetheless, these alternative studies allow independent reference points against which to 'reality check' EAPL's forecasts over the access arrangement period.

**Figure 2.4: Forecast NSW and ACT gas demand (PJ/year), 2001 to 2014**




**Sources: EAPL access arrangement** information, **p. 13.**
**AGA,** ***Gas Supply and Demand Study,*** **May 1997.**
**ABARE Research Report 99.4:** ***Market Developments and Projections to 2014-15.***
NSW **DOE,** ***Analysis of Energy Use in the NS W Manufacturing Sector,*** **June 1998.**

**A** number of observations can be drawn from the forecasts shown in Figure 2.4. Firstly, EAPL's forecasts of NSW gas consumption over the period between 2001 and 2005 contrast sharply with those of ABARE, **AGA** and **NIEIR.** This mainly reflects the estimated base level from which the forecasts were derived. The estimates for 1995 to 1998 relied upon by *ABARE,* **AGA** and NIEIR were much higher than the actual levels reached.[133]

EAPL projects demand to increase from 109.4 PJ in 2001 to 138.9 PJ in 2005, which represents an average annual compound growth of 6.1 per cent. The average compound growth rates forecast by ABARE, NIEIR and **AGA** are 4.1 per cent, 2.0 per cent and 0.7 per cent respectively, albeit from a much higher base.

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[132] **Duke Energy International advised that 13** PJ/year of **ethane was excluded from its NSW natural gas demand estimates,** ***Submission to ACCC for development of an access undertaking for the Eastern Gas Pipeline,*** **15 November 1999, p. 6.**

[133] **The quantity of gas consumed in NSW from 1995 to 1998 was: 1995, 98.1 PJ; 1996, 98.4 PJ; 1997, 104.6 PJ; and 1998, 106.6 PJ. Source: NSW** Ministry **of Energy and Utilities.**

Numerous studies have shown a direct correlation between growth in energy consumption and gross domestic product.[134] The forecasts by EAPL and ABARE of strong growth in gas consumption in NSW over the next five years are consistent with the long term growth projection in gross domestic product for both Australia and NSW.[135] The EAPL gas demand growth forecasts are likely to exceed the growth in gross domestic product.

Secondly, EAPL has forecast much lower gas demand in NSW than AGA, NIEIR and ABARE for each of the years from 2001 to 2005. However, the differences reduce somewhat after the initial access arrangement period. Nonetheless, EAPL's estimates are the lowest, (other than for 2008,2010 and 2012 when ABARE's forecasts are slightly lower).

Thirdly, in absolute terms, EAPL's forecasts are more closely aligned to ABARE than those of AGA and NIEIR. This may be due to the fact that ABARE's forecasts represent the latest studies for which data are publicly available.

Figure 2.5 provides a comparison of the various forecasts with actual gas consumption in recent years. It can be seen that EAPL's forecast are more consistent with historical results.

The Commission notes evidence of additional supply activity in NSW using Bass Strait gas. Duke Energy has reportedly signed two long term gas contracts which together commit it to supply approximately 20 PJ per annum – one with BHP Steel for all of its NSW sites and the other with Sithe Energies at Smithfield.[136] In addition, the Victorian-based energy retailer CitiPower is reported to have contracted with Duke Energy for on-sale of gas for three years in Sydney. Two NSW government-owned power companies, EnergyAustralia and Integral Energy are also reported to have contracted with Duke Energy.[137] While the Commission has not attempted to quantify the impact of these new supply arrangements, this activity would be expected to spur NSW gas demand.

The scheduled 1 July 2001 introduction of full retail contestability in NSW is also expected to drive demand. For example, AGL is reported as stating that 'competition will lead to a bigger overall gas market'.[138] Moreover, the entry of the EGP will help increase the penetration of gas in NSW and enable many industrial gas consumers in the Sydney, Wollongong and Newcastle areas and potential customers along the route to have access to gas for the first time.[139] Studies suggest that the overall size of the gas market is expected to expand significantly in the medium to long term.

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134 See ABARE Research Report 99.4, p. 23.

135 The projections for NSW's gross state product and Australia's gross domestic product from 1997 to 2015 are 2.7 and 2.8 per cent respectively. See AGA report *Natural gas consumption in Australia to 2015* prepared by NIEIR, October 1999, pp. 11 and 14.

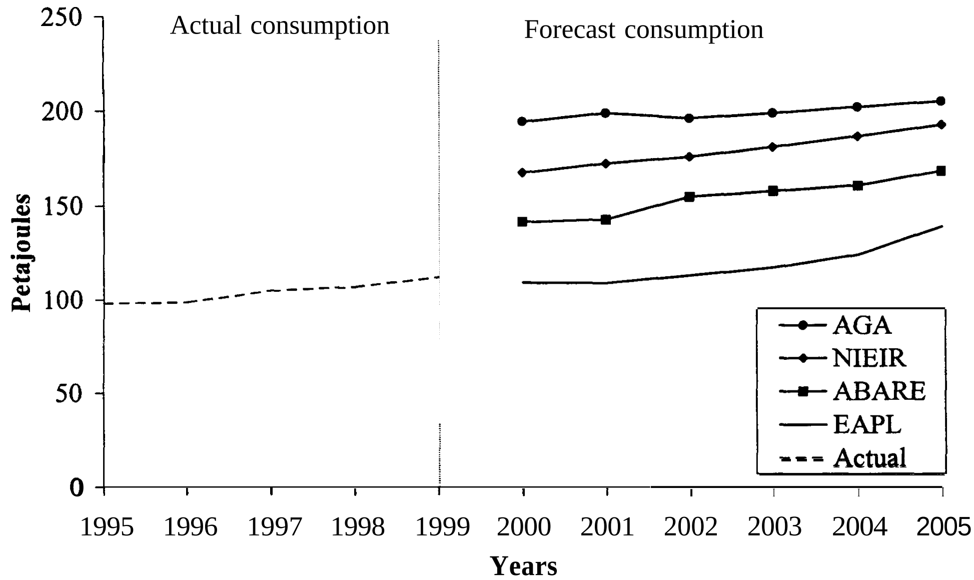
136 The Australian Gas Journal, April 1999, p. 18.

137 *Australian Financial Review,* 14 October 1999; and *Sydney Morning Herald,* 15 and 19 October 1999.

138 *Sydney Morning Herald,* 13 July 1999 and 23 September 1999.

139 *The Australian Gas Journal,* Vol. 63 No 1, April 1999, p. 17.

**Figure 2.5: Growth in gas consumption, NSWIACT 1995-2005**




Sources: Access arrangement information, p. 13 and information supplied by EAPL to the Commission.
AGA, *Gas Supply and Demand Study,* May 1997.
ABARE Research Report 99.4: *Market Developments and Projections to 2014-15.*
Ministry of Energy and Utilities, Analysis of Energy Use in the NSW Manufacturing Sector, June 1998.

*Electricity generation and cogeneration*

The Commission notes EAPL's view that growth in gas demand in NSW is largely a function of gas-fired power generation and cogeneration capacity. It also notes EAPL's assessment that this growth will not occur until after 2005. This view contrasts with earlier official studies. Recent studies by ABARE and NIEIR indicate that the power generation and cogeneration sectors are areas where strong growth in natural gas consumption is anticipated to the year 2014-15. For example, the annual use of gas in the electricity generation sector is projected to more than double between 1997-98 and 2014-15, increasing from around 170 PJ to almost 460 PJ Australia-wide. In the case of NSW, as a proportion of fuel used in electricity generation, natural gas is projected to increase from 1.8 per cent in 1996-97 to 11.7 per cent by 2014-15.[140]

The Commission notes reports that some planned NSW cogeneration and electricity generation projects have either been scaled down or deferred, and may now be expected to have little if any impact on gas demand before 2006. Firstly, it has been reported that EnergyAustralia has responded to low electricity prices by deciding to proceed with the ALISE's cogeneration project at Botany in two stages.[141] Secondly, AGA has reported a declining trend in the use of gas in the power generation sector over the last few years.[142] Thirdly, MEIR has reported that most of the major proposed electricity generations projects identified for NSW are likely to commence after 2005, including the Kurnell refinery project. In October 1999 it found that only a small number of these

140 AGA report Gas industry development strategy, 2000-2005, 1999, **p.** 12.

141 *Oil and Gas Australia,* September 1998, p. 72.

142 AGA, Gas industry development strategy, 2000-05, **p. 16.**

projects had been committed to, and that there was considerable uncertainty surrounding most of the other projects due to expected continued excess capacity and depressed electricity prices in NSW and uncertainty regarding access to fuel sources and the delivered price of natural gas.[143]

The Commission acknowledges that forecasting NSW natural gas consumption has proved difficult in the past, with considerable discrepancies between forecast and achieved volumes arising mainly because of the lumpy nature of large scale gas-fired electricity generation and cogeneration projects. Current projections are also subject to uncertainty. Nonetheless, the Commission is of the view that the studies and other information cited generally support the assumptions underlying EAPL's forecast of natural gas consumption in the electricity generation and cogeneration sectors.

***Quantity forecast to be transported** by **EAPL***

**As** shown in Table 2.24 EAPL anticipates that annual throughput on the MSP will fall substantially following commissioning of the EGP which it expects to commence operation with an initial load of about 20 PJ in the first year increasing to 60 PJ within several years. Annual MSP flows are forecast to fall from 117.7 PJ in 1999, reach a low of 89.8 PJ in 2002, then recover partly to 97.9 PJ by 2005 at the end of the initial access arrangement period. Volumes are forecast subsequently to grow considerably, reaching 147.4 PJ in 2010 and 198.2 PJ in 2020.

The Commission notes that the MSP volume forecasts presented in support of APT's stock market listing are consistent with those provided by EAPL in support of its proposed access arrangement.[144] The following assessment by ACIL Consulting was included in the APT offer document:

> Overall, ACIL considers the gas throughput forecast for the Moomba to Sydney Pipeline system and Central West Pipeline to be reasonable. It aligns reasonably well with other authoritative and publicly available demand forecasts and makes due allowance for the entry of new gas suppliers competing in the New South Wales and Australian Capital Territory markets and for opportunities to market gas from the Moomba to Sydney Pipeline system into Victoria.
>
> The main element of market uncertainty relates to the timing of new gas fired power generation facilities in the region. There is little doubt about their establishment in the long term, though there is a clear risk they may not be commissioned as early as anticipated. On the other hand there are powerful factors suggesting the contrary.
>
> APL's [Australian Pipeline Limited] estimates of the market likely to be captured by its new competitor, the Eastern Gas Pipeline, are considered reasonable. ACIL is satisfied that the throughput forecasts are appropriately cognisant of market and bypass risks generally, that prospective gas supplies are adequate to meet these forecasts and that regulatory developments likely to influence the quantity component **of** the revenue equation have been reasonably anticipated.[145]

*Conclusion*

**As** noted earlier, the Commission acknowledges that forecasting NSW natural gas consumption has proved difficult in the past. In particular, unforeseen delays in the

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[143] AGA, Natural gas consumption in Australia to 2015, October 1999, pp. 19-20.
[144] APT offer document, ***Buried Treasure,*** May ***2000,*** p. 28..
[145] APT offer document, ***Buried Treasure,*** May ***2000,*** p. 58.

construction and commissioning of large scale gas-fired electricity generation and cogeneration projects have led to substantial discrepancies between forecast and achieved volumes. Current projections are also subject to uncertainty for similar reasons, and because of the impetus following the introduction of new market players with the commissioning of the EGP and the opening of the retail sector to competition.

The Commission has carefully considered the methodology and assumptions underpinning EAPL's forecasts and their relationship with other studies. It has given particular weight to ACIL Consulting's overall endorsement of MSP throughput forecasts in the context of the APT listing on the Australian Stock Exchange.

The evidence available to the Commission does not provide it with grounds to conclude that the forecasts of gas to be transported by EAPL over the initial access arrangement period are unreasonable. The Commission notes that forecasts inherently involve a degree of risk, which in this case is an integral part of the proposed incentive mechanism whereby EAPL bears the risk of realised volumes being different to forecasts.[146] If actual volumes exceed forecasts, EAPL retains the profit. Conversely, if volumes are less than forecasts, EAPL will bear the loss. This arrangement should provide EAPL with an incentive to promote growth in gas volumes and the market as a whole.

Overall, the Commission is of the view that EAPL's forecasts of gas demand in NSW and ACT and the quantities of gas it expects to transport on the MSP satisfy the requirement of section 8.2(e) of the Code that any forecasts required in setting reference tariffs represent best estimates arrived at on a reasonable basis. Accordingly, the Commission proposes to accept EAPL's gas demand forecasts.

## 2.9 Cost allocation and tariff setting

### 2.9.1 Code requirements

Section 8.38 of the Code requires that, to the maximum extent that is commercially and technically reasonable, reference tariffs should recover costs directly attributable to the reference service and a fair and reasonable share of costs incurred jointly with other services. The Code (section 8.42) also requires that a particular user's share of costs to be recovered also follows these principles. These requirements must be met, regardless of the methodology used to calculate total revenue.

### 2.9.2 EAPL's proposal

Although EAPL is proposing two reference services, Class FT and Class STP, for cost allocation and tariff-setting purposes all revenue requirements are allocated to Class FT service and all STP capacity and throughput requirements are treated as Class FT requirements. Class STP tariffs are then derived from the resulting Class FT tariffs. EAPL has adopted this simpler approach, rather than the more precise approach of cost allocation between Class FT and Class STP services, because of the anticipated small

[146] Subject to any volume trigger or **risk** sharing mechanism incorporated in the access arrangement.

proportion of total revenue (less than 1.0 per cent) anticipated to accrue to STP services.

EAPL's methodology for determining its tariff structure is illustrated in Figure **2.6.** Essentially EAPL's methodology follows three steps:

- step 1: segregate the pipeline into 'mainline' and 'laterals' for tariff-setting purposes;
- step **2:** distinguish between fixed and variable costs; and
- step 3: allocate fixed costs to a capacity reservation charge and variable costs to a throughput charge.

The proposed categorisation of pipeline segments between mainline and laterals is as follows:[147]

- mainlines: Moomba to Young, Young to Wilton and Young to Culcairn; and
- laterals: Young to Lithgow (with spur lines to Bathurst, Cootamundra, Oberon and Orange), Junee to Griffith, and Dalton to Canberra.

EAPL's rationale for this segregation is that the two groups of pipelines have substantially different size characteristics in diameters, economies of scale and markets. EAPL has proposed to adopt a reference tariff structure with higher charges for laterals than the mainline pipeline. EAPL considers this reflects higher per unit costs on the laterals.

In support of its proposal to include the Young to Culcairn section as part of the mainline rather than as a lateral, EAPL notes that the Young to Wagga section did once serve the function of a lateral, delivering gas to regional centres only. However, following construction of the Interconnect, EAPL states that this segment of the MSP 'now links the NSW and Victorian transmission systems to new sources of gas supply and new markets.'[148]

Reference tariffs have been structured around tariff components that reflect the length of pipeline (distance) and quantity transported (service requirements). In support of a distance-based structure for reference tariffs, by which tariffs are calculated on a per kilometre basis, EAPL states that they are more directly cost reflective than zonal or postage-stamp rates and do not create artificial by-pass opportunities at zone boundaries. Moreover, a distance-based structure is readily accommodated on the MSP because it has relatively few receipt and delivery points.

The proposed tariffs are structured so that fixed costs are recovered through capacity charges and variable costs by throughput charges. EAPL refers to this approach as being Full Fixed Variable (FFV) or Straight Fixed Variable (SFV) with the associated

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[147] Access arrangement information, pp. **45-46.** The proposed segregation of the system into mainline and laterals for tariff-charging purposes would represent a departure from **EAPL's** existing third party access policy under which no distinction is made.

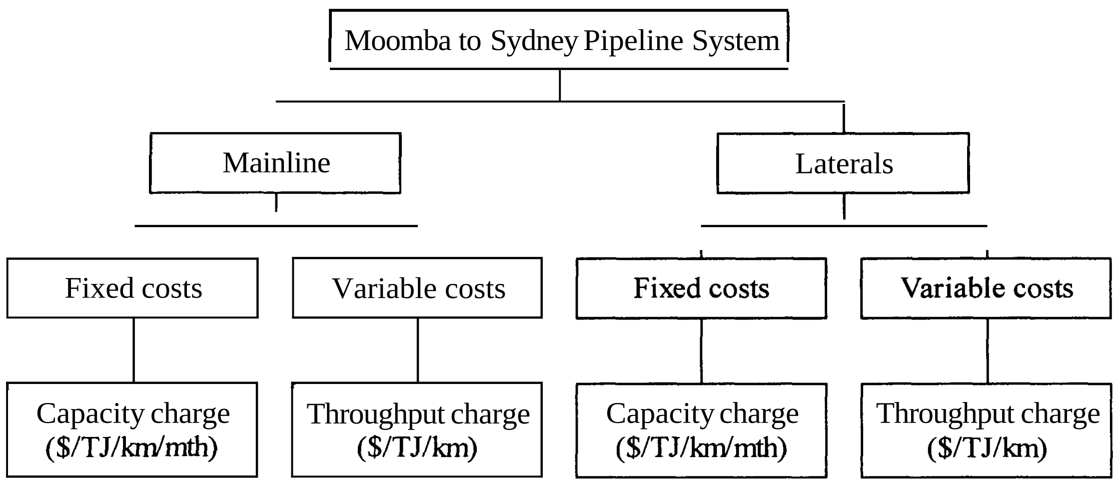
[148] **EAPL** response to submissions, 17 August 2000, p. **9.**

advantages of yielding optimal pricing during periods when pipeline capacity is not constrained and meeting EAPL's objective of encouraging use of the pipeline.[149]

The capacity requirements of a pipeline are often related more to peak service requirements than annual throughput. According to EAPL it is therefore appropriate that fixed costs be recovered by a capacity reservation charge and not a throughput charge, whereas those costs that vary with throughput (variable costs) should be recovered through a throughput charge.

EAPL's proposed tariff structure is summarised diagrammatically in Figure *2.6.*

**Figure 2.6: Reference tariff structure**




Cost allocators are used to apportion EAPL's total revenue requirements to the components of the reference tariffs. Essentially the cost allocators serve a dual purpose:

- to determine the proportion of total costs to be allocated between the mainline and laterals; and
- to classify costs into fixed costs and variable costs.

EAPL's major asset classes are pipelines, compressors, metering, plant and machinery and mobile equipment. The costs associated with these assets are return on capital and depreciation, which are fixed in nature and therefore allocated to the capacity component of the tariff. Allocation of these capital costs between mainline and laterals is based on each pipeline segment's relative share of the ORC value of the MSP. On this basis, the mainline accounts for 90.45 per cent of total asset value and the laterals the remaining 9.55 per cent. EAPL considers that allocation of costs on the basis of ORC rather than DORC avoids potential distortions caused by differing ages of assets.

149 Access arrangement information, p. 47.

EAPL's other major costs are operating and maintenance (O&M) costs including labour, general administration, materials, communications, gas used, licences and working capital. While these costs are more responsive to throughput than the capital costs mentioned above, a proportion of some of these costs remain fixed in nature. The ratio of fixed to variable costs varies depending on the cost category. Allocation of O&M costs between mainline and laterals is on the basis of pipeline length and asset values, resulting in 88 per cent of costs being allocated to mainline and **12** per cent to laterals.

A summary of the proportion of costs allocated between the various tariff components is shown in Table 2.25.

**Table 2.25: Allocation of costs to tariff components**

| | Mainline | | | Laterals | | |
|---|---|---|---|---|---|---|
| | **Capacity (%)** | **Throughput (%)** | **Total (%)** | **Capacity (%)** | **Throughput (%)** | **Total (%)** |
| Return on assets | 90.45 | 0.00 | 90.45 | 9.55 | 0.00 | 9.55 |
| Depreciation | 90.45 | 0.00 | 90.45 | 9.55 | 0.00 | 9.55 |
| O&M | 52.61 | 35.39 | 88.00 | 7.17 | 4.83 | 12.00 |
| Total cost allocation | 85.05 | **5.05** | 90.10 | 9.21 | 0.69 | 9.90 |

EAPL is proposing not to set tariffs strictly in accordance with the cost allocation indicated in Table 2.25. EAPL argues that, if the tariffs were based on a rigid application of the allocation of total revenue, the impact on transportation costs to users on the laterals would be excessive and may cause economic hardship to some rural industries and customers:

> If no regard is had for the sustainability of tariffs on lateral pipelines, a likely outcome is the loss of some loads with consequential disadvantage to all gas consumers.[150]

EAPL proposes to cap the lateral charges and to phase in lateral tariffs progressively over the access arrangement period. Under the cap on lateral tariffs, lateral reference tariffs would only apply to the first 100 km of any lateral pipeline. The mainline reference tariff would apply to the remaining length of the lateral pipeline.[151]

As a consequence of the cap and the phasing in of lateral tariffs, lateral tariffs would under-recover costs by **3.7** per cent. EAPL proposes to re-allocate this under-recovery to mainline tariffs. EAPL does not consider that such a cost re-allocation from laterals to mainline is necessarily evidence of cross subsidies. EAPL states:

> The route and length of the Moomba to Wilton Pipeline and the laterals have been determined to some extent by accidents of geography and the need for sound environmental practice. With different geographic circumstances, the laterals would be longer or shorter and the mainline may have been located closer to, or farther away

[150] EAPL response to submissions, 17 August 2000, pp. 8-9.

[151] For example, a user at Orange would pay the mainline tariff from Moomba to Young (1 033 km) the lateral tariff for the first 100 km from Young to Orange, and the mainline tariff for the remaining distance (38 km).

> from, some load centres. For example, the originally selected route for the mainline passed very close to Orange, Bathurst and Lithgow.[152]

Moreover, EAPL argues that the gas hauled through the laterals serves to reduce the mainline tariff, which would be around $0.08/PJ higher in the absence of the lateral pipelines.[153]

### 2.9.3 Submissions by interested parties

Incitec does not agree with EAPL's proposal to place a cap on lateral charges which would result in a re-allocation of 3.7 per cent in total revenue from the laterals to the mainline reference tariff. The reasons put forward by Incitec are:

- the fundamental principle of 'user pay' should underlie a tariff-setting mechanism. It is inappropriate for Sydney customers to subsidise assets for which they do not use;
- the subsidy is called for only because of the method of asset valuation, DORC valuation through a high rate of return (8.4 per cent) produces a revenue requirement so high that the market cannot meet it; and
- while investment in the laterals may have been on a reasonable basis at the time they were built, if they are no longer justifiable it may only be because of an unrealistic revenue expectation which flows from an overvalued asset.[154]

Incitec also questions the classification of the Young to Culcairn pipeline as a mainline, because relative to the Moomba to Wilton mainline, it is much smaller and has a smaller flow, and Incitec considers it has the characteristics of a lateral. Incitec's concern is whether the Young to Culcairn pipeline receives a subsidy from the Moomba to Wilton pipeline.

### 2.9.4 Commission's considerations

In assessing the issue of cost allocation, the Commission must consider whether costs directly attributable to a particular service or user have been allocated appropriately and whether joint costs are shared equitably.

***Segregation of pipelines into mainline and lateral***

The Commission considers it appropriate to apply different tariff structures to different pipeline segments when those segments have different utilisation rates and unit costs. Such an approach is consistent with the principles of the Code. On the whole, the lateral pipelines of the MSP have higher unit costs than the mainline. EAPL's proposed approach of introducing a higher lateral tariff than for the mainline is broadly cost-reflective. EAPL notes that while 9.9 per cent of costs are allocated to the lateral pipeline group, these pipelines deliver only 1.1 per cent of service requirements (capacity and throughput). However, such an allocation methodology is necessarily an approximation. For example, just as the mainline and laterals have different unit costs, so might particular pipeline segments within each of those two pipeline groups. This

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152 EAPL response to submissions, 17 August 2000, p. 8.
153 EAPL response to submissions, 17 August 2000, p. 9.
154 Incitec submission, 24 September 1999, pp. 1-2.

raises the issue of the possibility of cross-subsidies between pipeline segments and the potential for uneconomic by-pass. These issues are discussed later in this section.

*Capacity:throughput split*

EAPL's proposal to separate charges for capacity and throughput can be viewed as a two-part tariff. Two-part tariffs are common in industries displaying natural monopoly tendencies and for which traditional marginal cost pricing does not adequately recover costs. EAPL's two-part tariff structure is designed so that fixed costs are recovered through a charge for contracted capacity while variable costs are recovered through a charge based on the actual volume of gas transported by the user.

At issue is the appropriate proportion of a service provider's revenue that is recovered from the capacity charge compared with the proportion recovered from the throughput charge. There are marked variations in the capacity:throughput split across pipelines in Australia and overseas. Under EAPL's proposals, almost all of its revenue requirements would be recovered from the capacity charge, with a proposed capacity:throughput ratio of 94:6 for the mainline and 93:7 for the laterals. The amendments proposed in this ***Draft Decision*** (in particular the reduction in capital costs) would result in a capacity:throughput ratio of 92:8 for mainline pipelines and 90:10 for the laterals.

The Commission approved in its ***Victorian Final Decision*** a tariff structure based on a distinction between 'peak' and 'anytime' charges analogous to a capacity:throughput split in the proportion of 70:30.[155] It noted at the time a corresponding ratio in the UK of 55:45. In June 2000 the Commission approved a tariff structure for the Central West Pipeline based entirely on a commodity charge. It has been reported that the ratios in the US have been subject to frequent changes by the Federal Energy Regulatory Commission (FERC) since the 1940s.[156]

The Commission considers that the SFV approach proposed by EAPL has close links with the economic criteria for efficient pricing. A capacity charge reflects what the customer identifies as its maximum daily flow rate necessary to accommodate its needs over the period of its contract. The throughput charge reflects the actual transportation of gas on any day which may be much less than, but not exceed, a customer's reserved capacity. The capacity charge is linked principally with the capital costs of the pipeline and provides a meaningful guide for investment decisions while quantity charges are linked with variable costs which provide appropriate signals for usage at the margin.

An advantage of this tariff structure is that it requires a user to pay in proportion to its contribution to the maximum capacity demanded of the system. As the throughput charge is minimal compared with the capacity charge, this tariff structure should also encourage users to improve their load factors where practicable, therefore encouraging in an efficient utilisation of the pipeline.

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155 See ACCC, *Victorian Final Decision*, pp. 81-82.
156 JM Chermak and RH Patrick, *Incentives in Pipeline Pricing and Capacity*, Ed M Crew, *Incentive Regulation for Public Utilities*, Kluwer Academic Publishers, 1994, as cited by EAPL in its Access arrangement information, p. 47.

Accordingly, the Commission proposes to accept as reasonable EAPL's proposed proportion of its revenue requirements to be recovered by a capacity charge and a throughput charge, which reflects the ratio between fixed and variable costs. The Commission also proposes to accept the methodology adopted by EAPL for classifying costs into fixed and variable.

EAPL's approach to allocating depreciation and return on assets on the basis of ORC rather than DORC, to avoid distortions caused by differences in the ages of assets, appears reasonable. The Commission also considers that EAPL's proposal to allocate O&M costs on the basis of relative pipeline lengths and asset values is a reasonable approach to cost allocation for the mainline and laterals. As capital costs, as part of fixed costs, are by far the greater expense, the resultant tariff structure relies much more heavily on capacity charges than do the examples mentioned earlier. The Commission notes that this approach may not fully reflect the magnitude of fixed costs to the extent that O&M expenses are largely of a fixed nature since such activities are required regardless of the volume of gas flow.

*Distance-based pricing*

EAPL's proposed charges for reference services are also linked to the distance the gas is transported. The Commission considers that charges based on a per kilometre approach provide a simple way of differentiating between customers which require transport along different segments of the mainline and lateral pipelines. In this case, the distance-related charge as proposed by EAPL should be able to apportion costs appropriately among users.

*Allocation of costs between reference and non-reference services*

The Code requires a fair allocation of costs not only between different reference services, but also between reference and non-reference services. EAPL is proposing two reference services, Class FT and Class STP. For tariff-setting purposes EAPL has assumed that all STP volumes are Class FT volumes and therefore has allocated all costs to FT service. The Commission considers this approach reasonable, as the STP volumes are likely to be so small as to have minimal impact on revenue and little value is likely to be gained from a more precise allocation of costs.

EAPL's non-reference services as original proposed are the rebatable services and negotiated services. As the volumes applicable to rebatable services cannot be predicted with any certainty and the bulk of the revenue earned from rebatable services would be returned to eligible users, allocation of costs to rebatable services would not be required. However, APT has submitted that owing to changing circumstances since lodgment of the original access arrangement, the rebatable services as originally proposed are no longer viable. The issue of rebatable services is discussed in detail in Chapter 3.

A prospective user may negotiate different terms and conditions, including tariffs, when its requirements and circumstances vary significantly from the services provided for in the access arrangement. EAPL has not projected any revenue for negotiable services and accordingly has not allocated any costs to the service.

*Cross **subsidies***

Incremental costs and stand-alone costs define the lower and upper bounds in assessing the extent of any cross-subsidies. Under-recovery of incremental costs suggests that tariffs are too low for some customers and that other users on the system must make up any shortfall through increased tariffs. Over-recovery of stand-alone costs suggests that some customers are paying higher tariffs than can be justified and are subsidising other users on the system. In this case it would be more economic for those users paying higher than stand-alone costs to bypass the system, with the potential for higher tariffs to be imposed on other users.

To assess the likelihood of the existence of cross subsidies on the MSP, the Commission compared the incremental costs of each pipeline segment branching off the Moomba to Wilton mainline with each segment's contribution to the total revenue requirements of the system, including its contribution to the Moomba to Wilton mainline. For example, the Dalton to Canberra lateral's contribution includes revenue associated with load flowing from Moomba to Canberra, not just the revenue directly applicable to the Dalton to Canberra segment.

Precise calculation of incremental costs of each pipeline segment is difficult and any allocation of costs and assessment of the true extent of cross-subsidies is a matter of judgment. For the purpose of this exercise, those costs that can be directly attributed to a particular pipeline segment have been allocated to that segment (for example, the forecast cost of the Dalton to Canberra looping has been allocated to that lateral) while the remaining costs have been allocated on a similar basis to that used by EAPL to allocate costs between mainlines and laterals (for example, capital costs allocated on the basis of ORC).

A further consideration is whether the Contribution of any of the pipeline segments exceeds its stand-alone costs. Stand-alone costs are the costs above which a user will be inclined to by-pass a segment of the pipeline. In this instance costs based on DORC (plus operating costs) provide a reasonable measure of stand-alone costs. In this analysis it is appropriate to consider only the revenue directly related to the pipeline segment and to exclude its contribution to the mainline.

Higher tariffs for lateral pipelines are being proposed by EAPL to reflect different utilisation rates (and hence different per unit costs) between the mainline and lateral pipelines. However, not all of the lateral pipelines exhibit the same utilisation rate. Adoption of different tariff structures for individual pipeline segments to reflect differences in costs seems a reasonable approach, as users will pay only for those assets they use. However, the Commission's analysis indicates that EAPL's proposal of a common lateral tariff for the three segments, Young to Lithgow, Junee to Griffith, and Dalton to Canberra is not efficient.

**A** common tariff structure for the three laterals is derived by pooling the combined allocated costs of each lateral and deriving an average tariff. This approach results in tariffs on the Dalton to Canberra lateral in excess of stand-alone costs (as defined by DORC plus O&M costs), exposing the Dalton to Canberra lateral to the prospect of uneconomic by-pass. The Commission notes that, as the Dalton to Canberra lateral is only 58 km in length, users on this lateral do not derive **any** benefit from the 100 km cap.

Tariffs on the Dalton to Canberra lateral should be no higher than the tariffs that would be derived by applying a value to the pipeline equivalent to DORC plus operating and maintenance costs.[157] Accordingly, the Commission proposes an amendment to this effect.

**Proposed amendment A2.10**

> In order for EAPL's access arrangement for the MSP to be approved, the reference tariffs applicable to any pipeline segment of the MSP should be no higher than tariffs consistent with that segment's costs based on DORC (plus operating and maintenance costs).

***Phasing in of lateral tariffs and 100 km cap***

EAPL states that, in the absence of the phasing in of the full cost-reflective tariffs and the 100 km cap on the laterals, tariffs to some customers would be excessive and cause economic hardship. EAPL considers this would result in unsustainable tariffs which would be likely to lead to some loss of load which would be detrimental to all customers.

According to Incitec the proposed **3.7** per cent reallocation of costs from laterals to the mainline is the result of a high asset base valuation and high rate of return producing an unsustainable revenue requirement. Implementation of the proposals contained in this *Draft* ***Decision*** would significantly reduce EAPL's revenue requirements and the overall tariffs faced by users of the MSP. These reductions would largely alleviate the problems identified by EAPL that lateral tariffs based on full cost recovery would be excessive. While some customers would incur increased tariffs to the lateral portion of their total tariff, at the same time they would benefit from lower mainline tariffs.

Under EAPL's proposal, some end-users of the laterals would pay substantially higher tariffs. For example, domestic loads distant from the mainline would face real price increases of up to approximately \$0.70/GJ. Application of the proposals contained in this ***Draft Decision*** would result in users of the laterals generally enjoying tariff decreases. In some cases comparatively small real increases would occur (see Chapter 2.9). The Commission considers it appropriate where possible that service providers be able to earn a commercial return on each segment of their investments. Lower earnings on particular classes of assets may discourage investment in infrastructure segments or regions. The Commission proposes the following amendment to remove the phase-in mechanism.

[157] The Commission's analysis takes into consideration the costs of duplicating the Dalton to Canberra lateral. While the Commission notes the construction **of** a lateral pipeline from the **EGP** to Canberra potentially in competition with the MSP, the difficulties of using the costs **of** the EGP as **a** benchmark for costing the MSP were noted in section **2.2.4.**

**Proposed amendment A2.11**

In order for EAPL's access arrangement for the MSP to be approved, EAPL should introduce a more cost-reflective tariff structure by dispensing with the phasing in of the lateral tariffs.

The Commission has considered EAPL's proposal to impose a 100km cap on lateral tariffs to avoid substantial tariff rises for lateral users distant fi-om the mainline. Application of the proposals contained in this *Draft **Decision*** would reduce but not remove these increases. While EAPL's approach may appear to depart from the general principle of cost-reflective pricing, the Commission is aware that network pricing issues can be complex. For example, as EAPL has noted, lateral users also contribute to the costs of the mainline. In the absence of the lateral users, mainline users would experience an increase in tariffs. It is not clear that this approach represents a cross-subsidy from mainline users to lateral users. The Commission proposes to accept EAPL's proposed 100km cap on lateral tariffs for the initial access arrangement period.

## 2.10 Tariff path and incentive structure

### 2.10.1 Code requirements

Section 8.3 of the Code provides discretion to service providers in how the reference tariffs may be vaned during an access arrangement period. For example, tariffs may change according to a price path approach where tariffs follow a path determined at the start of the period. The price path is adjusted at the start of the next period. The alternative method specified in the Code is the cost of service approach. Tariffs are set according to forecast costs and are adjusted throughout the access arrangement period in light of actual outcomes. The Code also allows variations or combinations of the approaches to be used.

Section 8.44 of the Code also states that the reference tariff policy should, where the regulator considers appropriate, contain a mechanism to enable a service provider to retain some, or all, of returns which exceed the expected level, particularly where these increased returns are due to the service provider's efforts. This incentive mechanism should encourage the service provider to increase sales volumes, minimise costs, develop new services, and undertake only prudent investment. It should also ensure that users gain from any increased efficiency, innovation and improved sales volumes but not necessarily in the same access arrangement period as that they occur. The incentive mechanism may include:

- specifying that tariffs are based on forecast, not realised, variables;
- setting a target revenue and specifying how revenue in excess of this is to be shared between the service provider and users; and
- a rebate mechanism for rebatable services that does not provide a full rebate to users.

Under section 10.8 of the Code, a rebatable service is defined as one for which there is substantial uncertainty regarding future revenue fiom sales of the service, and the nature of the service is substantially different to any reference service.

Section 8.40 of the Code provides that if revenue reflects costs (including capital costs) that are attributable to providing the reference service jointly with a rebatable service, then all or part of the total revenue that would have been recovered fiom the rebatable service may be recovered fiom the reference service provided that an appropriate portion of any revenue realised fiom sales of any such rebatable service is rebated to users of the reference service through reduction in reference tariff or a direct rebate to the relevant user or users. The structure of such a rebate mechanism should be determined having regard to the following objectives:

- providing the service provider with an incentive to promote the efficient use of capacity, including through the sale of rebatable services; and
- users of the reference service sharing in the gains from additional sales of services, including from sales of rebatable services.

### 2.10.2 EAPL's proposal

EAPL proposes to offer a range of tariffs for different classes of service. It proposes to offer two types of reference services (Class FT and Class STP) for both the mainline and lateral pipelines, including a backhaul transportation rate. Non-reference services being offered are: three types of rebatable services (Class WTF, Class OFT, Class IT) and a negotiable service.

A summary of proposed charges for services for the first year of the access arrangement period is shown in Table 2.26. These classes of service are defined more fully in Appendix C of this *Draft Decision.*

### Table 2.26: Summary of EAPL's proposed charges for services for 2000/2001

| Class of Services | Capacity Charge ($/TJ/day/km/mth) | Throughput Charge ($/TJ/km) | Other Charges |
|---|---|---|---|
| Firm Service Class FT | ***Mainline*** $15.26 ***Laterals*** $38.17 | ***Mainline*** $0.0434 ***Laterals*** $0.210 | Overrun charge: (i) authorised overruns at the rate of 200% of capacity charge; and (ii) non authorised overruns at 350% of capacity charge Balancing charge: (a) EAPL may impose a charge of 150% of the purchase price of gas paid by EAPL to restore the user to zero inventory plus a service fee of $2 000 per occurrence. Odorisation Charge: EAPL may impose reasonable charges for odorisation which is expected to be less than $0.01/GJ of gas delivered to the user |
| Small Takeoff Points- Class STP | ***Mainline*** Pro rata to Annual Quantity (AQ) in Terajoules at 80% Load Factor, from zero to 200 TJ/pa. $\frac{1.25 \times \$15.26 \times AQ}{200 \times 30.4375}$ ($/TJ/km) ***Laterals*** Pro rata to Annual Quantity (AQ) in Terajoules at 80% Load Factor, from zero to 200 TJ/pa. $\frac{1.25 \times \$38.17 \times AQ}{200 \times 30.4375}$ ($/TJ/km) | ***Mainline*** $0.0434 TJ/km ***Laterals*** $0.210 TJ/km | Overrun charge: Not applicable (na) Balancing charge: as per Class FT service Odorisation charge: as per FT service Minimum annual charge of $6 000 applies. |
| Backhaul- Class FT and STP | 50% of capacity charge | Nil | Na |
| Rebatable Services (WFT, OFT and IT) | Tariff and charges to be determined in accordance with bidding procedures by EAPL | | Overrun charge: as per Class FT Balancing charge applies Odorisation charge applies |
| Negotiable Service | Negotiable terms and conditions, including tariffs | Negotiable | Negotiable |

#### *Reference services – Class FT (firm transportation): mainline and laterals*

Table **2.27** shows the proposed tariffs for a firm transportation service for each of the years during the initial access arrangement period (between 2001 and 2005) for both mainline and laterals. Other charges associated with the class FT service include overrun, balancing and odorisation.