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DEPARTMENT OF MINES & ENERGY
SOUTH AUSTRALIA

REPORT BOOK NO. 858

1989 ECONOMIC MODEL OF THE COOPER BASIN

OIL, GAS & COAL DIVISION

by

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SR 28/1/120
SR 5/6/187

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1989 ECONOMIC MODEL OF THE COOPER BASIN

Introduction

This report is a summary of the 1989 Economic Model of the Cooper Basin. It is essentially a status report and will form a basis against which future directions will be taken.

The major assumptions forming the basis of the model are documented. The first use of the economic model was for the Royalty Presentation on 21 August 1989.

TARDIS Update

The TARDIS input data has been reviewed and updated to be current at 1/1/89. A comprehensive summary of the work done is listed in Appendix A. The updated TARDIS runs have are based on the 1989 Reserves Atlas. The following parameters were revised :

- OGIP,
- Gas compositions,
- Recovery factors,
- deliverability curves,
- exploration model.

The new runs are also run against the OEP forecast of demand by both PASA and AGL rather than the contract quantities that have been used in the past. The exploration objective has also been altered to reflect the contractual situation, (see Appendix A for details).

It should be noted that the ethane consumption as fuel has been reviewed after analysis of recent CHAP reports. It is estimated that future ethane consumption at both Moomba and Port Bonython will be about 8% of the total ethane throughput, (see Appendix B).

Economic Model Review

A review of the economic model was performed by loading the actual 1988 data into the model and comparing it with the royalty return. Some adjustments to operating costs were made at this stage. The comparison confirmed that the model is indeed working within acceptable accuracy. The details of this review are listed in Appendix C.

Economic Model Update

The economic model, PECAN, has been updated and modified to accommodate for the current and proposed contractual and royalty scenarios. These are summarized in Appendix D. The model has been modified as follows :

- Queensland gas may be included if required,
- field fuel factor applied to raw gas to plant,
- oil volumes reset to barrels,
- operating costs revised,
- crude price as per the 1989 ABARE forecast,
- 1989 LPG price = $165/t,
- 1989 gas price = $1.86/GJ.

The liquids pricing details are listed in Appendix E.

The revisions to operating costs are listed in Appendix C.

Economic Model Input Data

The bulk of the input data for the economic model is generated by TARDIS. However, TARDIS does not generate a crude oil production profile or well count for oil fields. The crude oil production forecast is taken from the Santos 1989 Preliminary Development Plan, while the prediction of oil wells on-line is based on information presented in the Santos 1989 Development Plan. These estimates are presented in Appendix F.

A number of minor modifications were made to the TARDIS output prior to input into the PECAN model. The details are listed in Appendix G.

Royalty Review Committee

The results of the work done are listed in a series of attachments which were presented to the Royalty Review Committee on 21 August 1989.

Table 1 lists the existing and proposed royalty scenarios.

Table 2 lists the economic assumptions used. It should be noted that the 1989 sales gas price used was incorrect and should be $1.86/GJ. This mistake has been rectified.

The TARDIS assumptions are listed in Table 3.

Figure 1 shows the before tax net cash-flow in constant 1989 dollars under both the proposed and existing royalty schemes. This shows that the effect of the new royalty regime on the net cash-flow to the producers is very small. The rise in revenue from 1994 to 1999 is due to the rich undiscovered fields dominating production. The fall in cash-flow after 2001 is due to the decrease in gas to be supplied to AGL according to contract, which ceases in 2006. The gradual rise in cash-flow after 2009 is a result of the ABARE liquids price forecast, which assumes a 2.2% real growth.

It should be noted that the net cash-flow has no direct relation to the royalty received. The net cash-flow is not the assessable income for royalty, but rather includes capex not allowable as royalty deductions. The net cash-flow also includes the royalty deduction.

Figure 2 is a comparison of the NPV of the project under the respective royalty schemes. It shows that under the proposed scheme, the IRR of the project is reduced from 20.8% to 20.5%.

Figure 3 is a comparison of the estimated royalties received under both schemes. The figure shows that under the new regime, the royalties received will approximately double. The reasons for the general shape of the curves are similar to those for Figure 1.

Table 4 is a summary of the royalty received expressed as a percentage of the gross revenue until 1995 under both royalty regimes. Under the proposed regime, the royalty received rises to a level of 8.5% of the gross revenue. It is lower for the first few years as the effects of the depreciation of capital expenditure incurred prior to 1989 are still felt in this period.

Comments

1. **Ethane**

The runs done to date have virtually ignored ethane. All ethane produced has been assumed to be sent to storage, in either a storage reservoir or an EOR scheme. In some ways, ethane storage is beneficial to the producers as it helps to maximize liquids recovery. However, no sales value is attached to the ethane under the current scenario. Ethane is available to the producers for use in peak shaving.

According to the report "The Value of Cooper Basin Ethane for Peak Shaving", (SR 28/1/88/1), if 3 PJ/yr of ethane are included in the sales gas stream for peak shaving purposes, the MDQ factor can be reduced to 1.024. The OEP seem to have overlooked this factor in their directives to us regarding the annual demand. TARDIS should be run with 3 PJ/yr of peak shaving ethane taken into account.

A further problem is in dealing with that ethane which is currently being stored. Under the current TARDIS run, which includes the full exploration model, approximately 500 PJ of ethane is produced over the life of the project. It should be noted that this volume is a function of the assumed composition of the undiscovered gas fields, however it is not considered that this will greatly affect the estimate.

At this stage, the ethane issue is to be put into the "too hard basket". This is because there is currently no clear-cut way of dealing with the ethane. The possible options are to inject the ethane directly into the sales gas stream or to sell the ethane as petrochemical feedstock. The latter option is unlikely at this stage. The former option can not be readily employed without running in to Wobbe Index problems. If greater than 10 PJ/yr of ethane is added to the sales gas stream under all foreseeable circumstances, (i.e. the SA demand supplied only after 2006), the Wobbe Index is exceeded.

It should be noted that it is not considered that a change to how we are handling ethane at the moment will alter the broad thrusts of the royalty study.

2. **Zone 2 composition**

One reason for the sharp rise in the royalty received over the period 1995 - 1997 is the dominance of the newly discovered fields on gas supply. These fields are assumed to have a composition which is the number average of all fields discovered to date. This average is liquids rich. In the early part of the run, rich fields are balanced by dry fields to reduce the total liquids production. In later years the undiscovered fields dominate. A check on the number average of the latest list of compositions showed that the assumed composition in TARDIS is quite reasonable, being if anything, a little dry.

3. **Liquids price forecast**

The liquids price forecast impacts on the shape of the royalty received prediction. There is a rise in both net cash-flow and royalty after 2006 due to the fact that liquids prices increase in real terms according to the ABARE forecast. This may require some refinement, but again the broad conclusions of the study thus far are not affected by this assumption.

Future Directions

As pointed out previously, at this stage it is not necessary to adjust the model too much further as the conclusions drawn from the study so far are unlikely to be affected by such refinement. It may be necessary to consider the parameters discussed previously if absolute numbers are required.

The main points of interest that need to be investigated are the different components of the new regime in terms of both the base and the rate to determine their relative importance. It is in this area that the effort will thus be concentrated in the short term.

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M Malavazos

Michael Malavazos

24/8/89

COMPARISON OF ROYALTY REGIMES

TABLE 1.

	EXISTING REGIME	PROPOSED REGIME
1.	Wellhead value = Gross revenue – post wellhead opex – total annual credit foncier.	Wellhead value = Gross revenue – post wellhead opex – depreciation – allowable interest.
2.	Royalty rate = 10% of wellhead value.	Royalty rate = 12.5% of wellhead value.
3.	Operating expenditure includes overheads.	Operating expenditure includes overheads.
4.	Capital expenditure and interest deducted on a credit foncier basis.	Capital expenditure is depreciated on 10% straight line basis.
5.	Royalty paid 6 monthly.	Royalty paid monthly.
6.		Allowable interest is calculated at the Long Term Bond Rate, assumed for future projections to be 10%, on remaining undepreciated capital, assuming a 50% debt/equity ratio.

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Table 2

ROYALTY REGIME INVESTIGATION

ECONOMIC ASSUMPTIONS

1. 1989 sales gas price = $1.83 / GJ, (later adjusted to $1.86/GJ).

2. Gas price inflated annually by 95% of CPI from 1990 to 1998 and by the full CPI thereafter.

3. Crude and condensate prices as per the 1989 ABARE forecast.

4. 1989 LPG price = $165 / tonne.

5. Crude, condensate and LPG prices increase by 2.2% in real terms, according to the ABARE forecast.

6. Post 1989 CPI = 6%.

Table 3

ROYALTY REGIME INVESTIGATION

TARDIS ASSUMPTIONS

1. Basin fully explored.

2. Exploration scenario = 200 PJ/yr of sales gas-in-place for first three years, and 90 PJ/yr thereafter. (Equivalent to 150 PJ/yr and 68 PJ/yr thereafter of deliverable sales gas).

3. DME estimates for proved, probable, possible and potential gas reserves as at 1/1/89.

4. Cooper Basin partner's 1989 oil production forecast with no new oil discoveries.

5. Ethane sent to storage for the life of the project.

6. PASA and AGL forecast supply requirement.

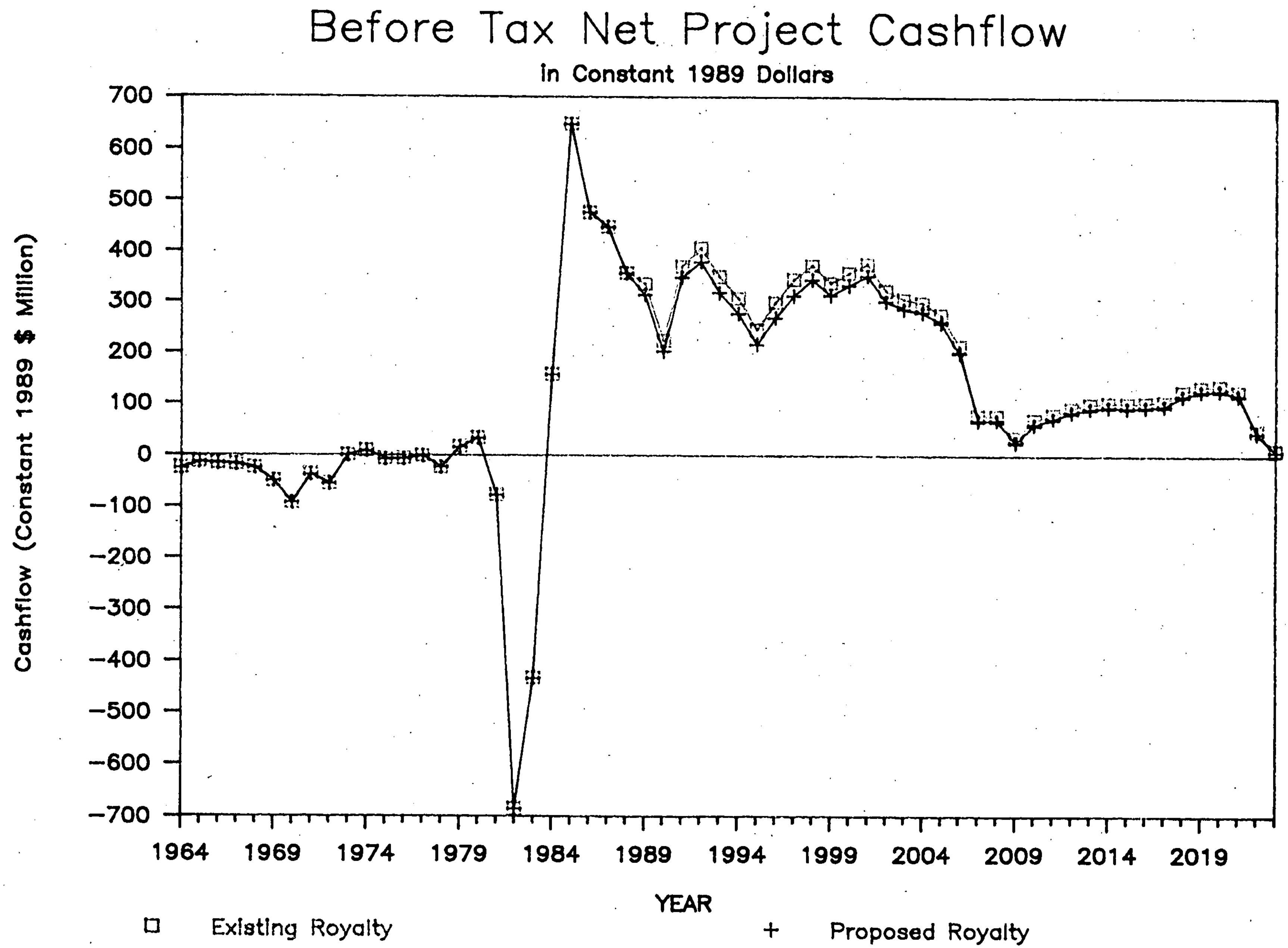
7. 30 PJ of annual gas market supplemented by gas purchased from outside S.A. from 1/1/94.

ROYALTY RECEIVED EXPRESSED AS A PERCENT OF GROSS REVENUE

All values are in constant 1989 dollars.

year	Gross Revenue ($m)	Existing Regime ($m)		Proposed Regime ($m)	
1989	673	26.11	3.9%	44.74	6.6%
1990	651	23.12	3.6%	41.44	6.4%
1991	637	23.33	3.7%	42.39	6.7%
1992	636	25.13	4.0%	48.75	7.7%
1993	621	24.88	4.0%	52.66	8.5%
1994	519	17.71	3.4%	44.20	8.5%
1995	490	16.50	3.4%	42.36	8.6%

TABLE 4



Before Tax Net Project Cashflow
In Constant 1989 Dollars
Cashflow (Constant 1989 $ Million)
700
600
500
400
300
200
100
0
−100
−200
−300
−400
−500
−600
−700
1964
1969
1974
1979
1984
1989
1994
1999
2004
2009
2014
2019
YEAR
□ Existing Royalty
+ Proposed Royalty

FIG. 1.

NPV @ 1989 of Project

1964–2034 Before Tax Cashflow

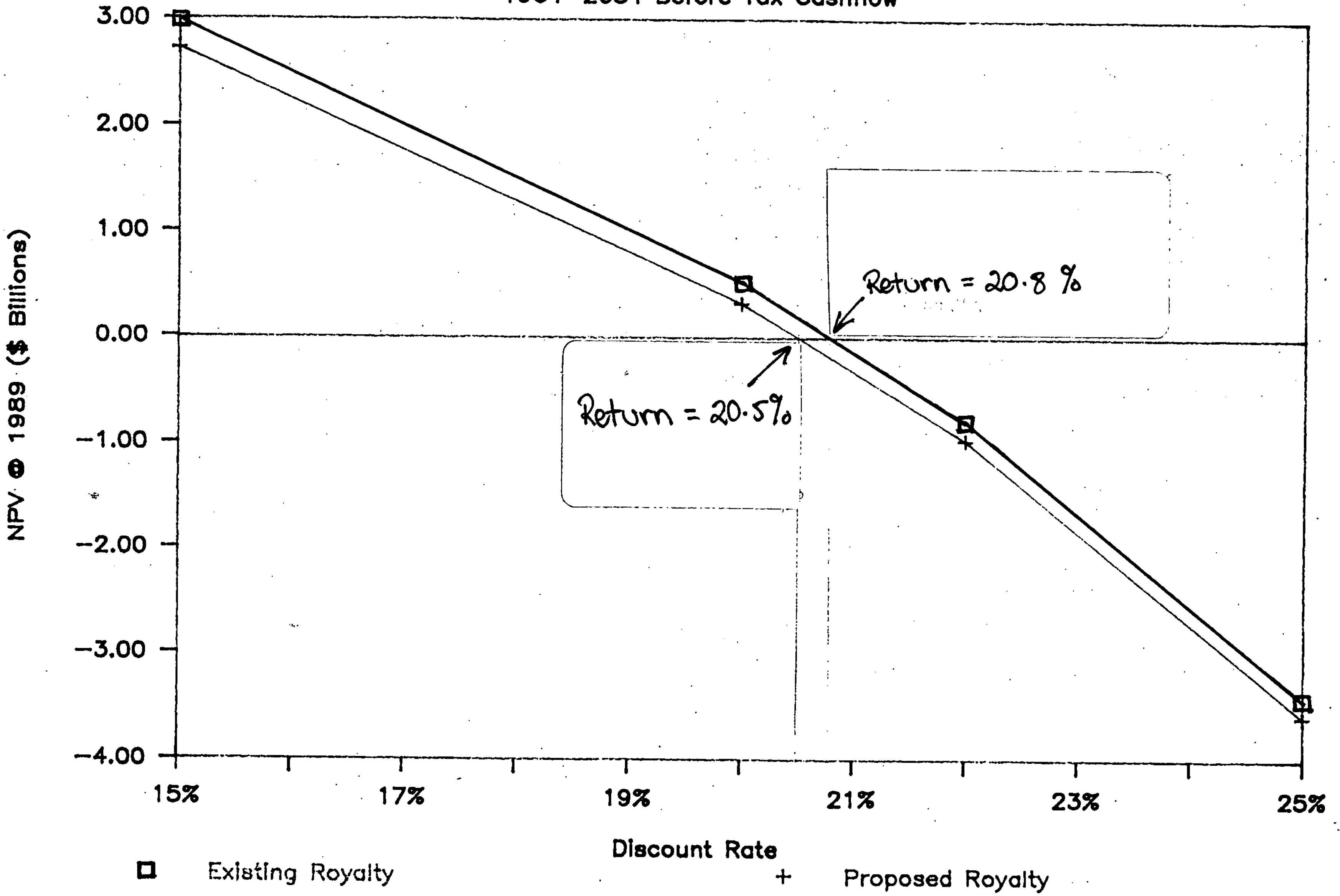
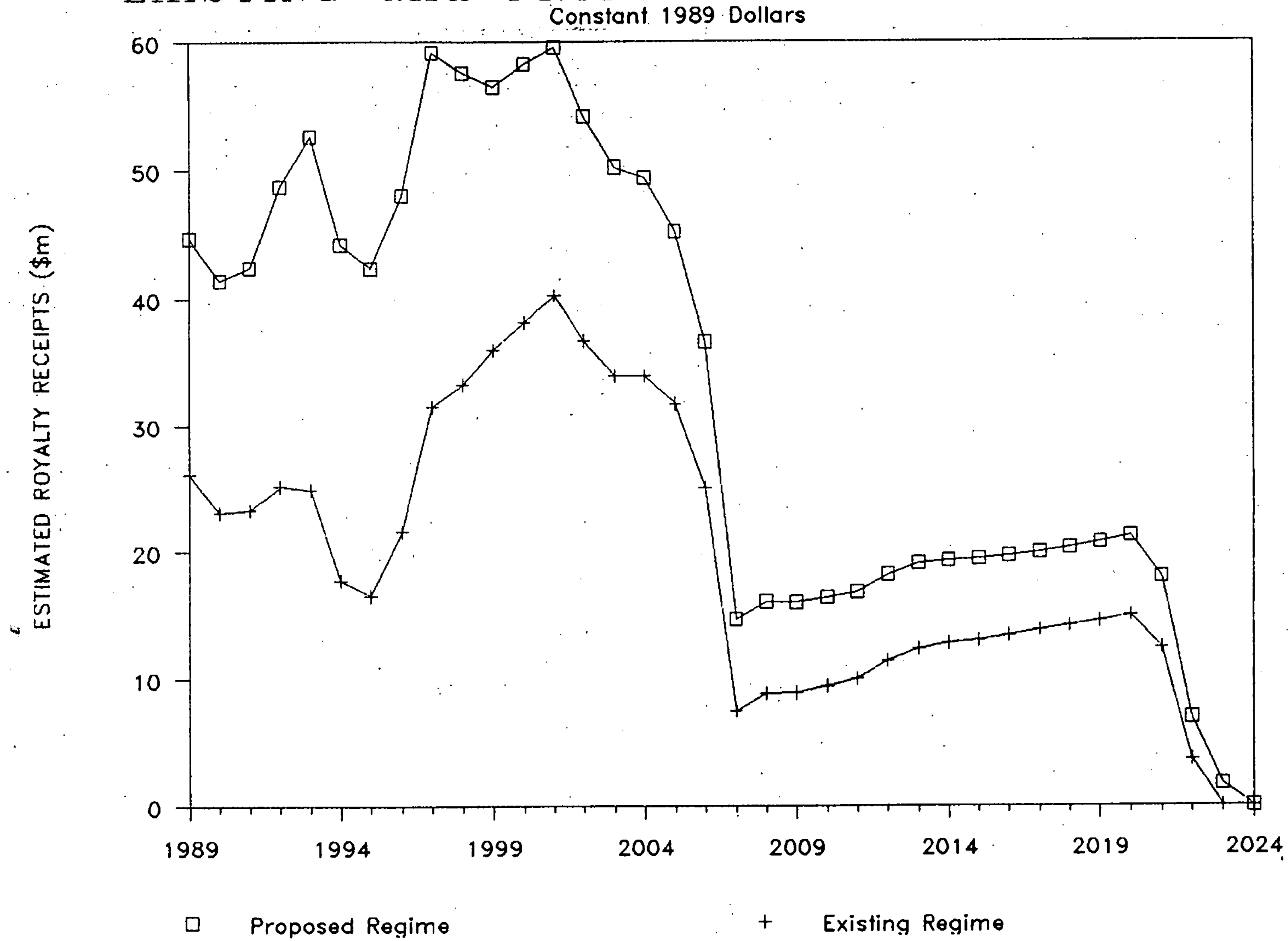


Fig. 2.

EXISTING and PROPOSED ROYALTY REGIMES



12.

FIG 3.

Appendix A

TARDIS RUNS FOR ROYALTY REVIEW

(August 1989)

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INTRODUCTION

A series of TARDIS runs are to be run to provide input data to the economic model as part of the new royalty review. New TARDIS runs are required for the following reasons :

1. The previous royalty figures are based on 1/1/88 data. Since then, there has been a complete review of Original Gas-in-Place, recovery factors, gas composition, deliverability curves and, the gas discovery algorithm.

2. Previous TARDIS runs have been to to investigate the gas supply against contract rather than forecast demand. Forecast demand is often significantly less than contract. The new TARDIS runs are required to supply the performance of the South Australian gas fields against the best estimate of the demand. This forecast must therefore account for the predicted supplement of 30 PJ/yr from a source outside the State. This scenario is considered the most appropriate for royalty predictions.

COMMENT

A discussion of the model constructed for the TARDIS runs is given below.

1. **Reserves Data**

   There has been a comprehensive review of reservoir data since 1988. All data for the new set of TARDIS runs is sourced in the 1989 Reserves Atlas and is current to 1/1/89. This review covers the following aspects of reserves and gas supply estimation :

- OGIP,
- Gas compositions,
- Recovery factors,
- deliverability curves,
- exploration model.

2. Forecast Demand

The TARDIS runs for royalty estimation contain the best estimate of the supply requirement from the South Australian gas fields. This is listed on Table 1. The forecast PASA demand is from a minute to the Director, Oil, Gas and Coal from the Office of Energy Planning dated 26/4/89. This minute indicates that the forecast AGL demand should be taken from the Santos 1989 Firm Budget Gas Forecast.

The PASA demand forecast assumes that 88 PJ will be required in 1989 and 86 PJ/yr until 1999. For the purposes of this run, it is assumed that the PASA demand will remain at 86 PJ/yr beyond this date.

The AGL forecast demand takes the Santos estimate of demand until 1993. From this time until the year 2000, Santos assume that the AGL demand will in fact be contract demand. Santos then predict a shortfall in 2001. For our purposes, it is assumed that the AGL demand will be contract demand rather than Santos supply, as the Santos supply reflects their inability to meet demand rather than their view of the supply requirement.

A further complication to the supply requirement is the fact that under the current view, it is likely that a contract for 30 PJ/yr of sales gas sourced from outside of the State will be written. The supply is expected to begin between 1992 and 1994. For our purposes we assume that the contract will begin at 1/1/94. This has the effect of reducing the demand on South Australian gas fields.

3. Exploration Scenario

The gas supply is heavily dependent on the gas exploration objective employed. This in turn impacts on exploration drilling requirements and filters through to royalties. It is therefore necessary to optimise the exploration drilling effort to maximise the supply while minimizing the drilling effort. This was finalized on TARDIS prior running the economic model.

The Heads of Agreement for the 1989 Gas Contracts calls for the Producers to discover 150 PJ/yr of sales gas reserves for the years 1989, 1990 and 1991.[1] The sales gas reserves are to be "deliverable between 1 January 1992 and 31 December 2001". [2] This scenario must therefore be built into the TARDIS model. The exploration objective set discovers gas-in-place rather than gas reserves. It is therefore necessary to divide the reserves requirement by the recovery factor, (for undiscovered fields, this is 75%), to calculate the required gas-in-place exploration objective. In order to discover 150 PJ of sales gas reserves, it is necessary to find 200 PJ of sales gas-in-place.

The subsequent exploration program must has been optimised such that sufficient reserves are discovered to delay the shortfall as long as possible. The optimum objective was found to be 90 PJ/yr of sales gas-in-place for the remainder of the project.

4. Plant Extraction Factors

The model sets these figures on a field specific basis. The average yearly plant extraction factors are of the order of 25% - 30% for ethane and 3% - 4% for propane. This compares with figures of 25% for ethane and 3% for propane used by Santos in their recent SIPS runs.

The variation in the TARDIS plant factors with time is a reflection of the fact that when drier fields dominate production more ethane must be let into the sales gas stream in order to maintain its heating value.

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1. 1989 Gas Sales Head Agreement, Clause 8.2.

2. Ibid, Clause 1.1.2.

Table 1

GAS SUPPLY REQUIREMENT FOR NEW ROYALTY RUNS

year	PASA Demand (PJ)	AGL Demand (PJ)	Supplementary Contract (PJ)	Total Demand on SA gas (PJ)
1989	88.0	95.0	0.0	183.0
1990	86.0	100.4	0.0	186.4
1991	86.0	105.9	0.0	191.9
1992	86.0	111.3	0.0	197.3
1993	86.0	118.7	0.0	204.7
1994	86.0	118.7	30.0	174.7
1995	86.0	118.7	30.0	174.7
1996	86.0	118.7	30.0	174.7
1997	86.0	118.7	30.0	174.7
1998	86.0	118.7	30.0	174.7
1999	86.0	118.7	30.0	174.7
2000	86.0	118.7	30.0	174.7
2001	86.0	115.4	30.0	171.4
2002	86.0	103.8	30.0	159.8
2003	86.0	93.3	30.0	149.3
2004	86.0	84.1	30.0	140.1
2005	86.0	75.7	30.0	131.7
2006	86.0	50.3	30.0	106.3
2007	86.0	0.0	30.0	56.0
2008	86.0	0.0	30.0	56.0
2009	86.0	0.0	30.0	56.0
2010	86.0	0.0	30.0	56.0
post 2010	etc	etc	etc	etc

(as per OEP advice 10/8/89)

Appendix B

ETHANE FUEL CONSUMPTION FOR ROYALTY RUNS

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This is a brief review of recent ethane usage intended to quantify the expected fuel consumption at both Moomba and Port Bonython.

The CHAP data since February 1988 is listed on Table 1. The data for October and November 1988 was not available at the time and was not used. It is not expected that this will seriously affect the conclusions drawn.

Inspection of Table 1 shows that the total consumption of ethane at both Moomba and Port Bonython has consistently been of the order of 10% for the last 18 months. However, the fuel at Port Bonython is now being used to supplement the fuel requirements. The annual sales gas fuel consumption is expected to be about 5 PJ/yr, reducing the ethane requirement by about 25%, (see Ethane Use Review SR 28/1/88/1). This will reduce the total ethane fuel usage to about 8%, (see attachment).

It is not necessary to adjust the sales gas plant fuel factor due to the fact that some is to be used at Port Bonython. This is because the usage at Port Bonython compared to the Moomba plant fuel is negligible. It would be false accuracy to try and account for this.

TABLE 1 : Ethane Stream Breakdown from Recent CHAP Data.

*** UNITS are TONNES ***

CHAP RAW DATA

	Injection	Moomba Flare	Moomba Fuel	Pt.Bon. Prop.	Pt.Bon. Fuel	Sales gas	Opening - Closing	TOTAL
FEB'88	20578	827	1703	81	3164	13667	15528	55548
MAR'88	1228	329	1525	506	3221	13738	35349	55896
APR'88	8288	2366	1337	505	2765	12993	29276	57529
MAY'88	24299	3152	1970	313	3148	18490	11183	62555
JUN'88	21783	4	2315	214	3163	20425	13953	61857
JUL'88	28580	278	2274	593	3465	20796	7873	63857
AUG'88	32412	585	2343	107	3704	18818	6327	64295
SEP'88	31354	1428	1803	581	3752	16765	3551	59234
OCT'88								
NOV'88								
DEC'88	28961	321	1831	436	3472	17671	2946	55638
JAN'89	28944	570	1724	280	3197	11656	10327	56697
FEB'89	26065	306	1395	481	3514	12477	7587	51826
MAR'89	32794	241	1473	75	3769	14562	4925	57839
APR'89	36728	302	1623	602	3463	13243	195	56155
MAY'89	36228	193	1428	76	2499	14819	3231	58474
JUN'89	28827	159	1903	597	2835	25533	1543	61398
TOTAL	387067	11060	26645	5447	49130	245654	153794	878797
DEC'88-JUN'89	218546	2091	11376	2547	22750	109962	30754	398026

ETHANE STREAM BREAKDOWN

	Injection	Moomba Flare	Moomba Fuel	Pt.Bon. Prop.	Pt.Bon. Fuel	Sales gas	Opening - Closing	TOTAL
FEB'88	37.05%	1.49%	3.07%	0.14%	5.70%	24.60%	27.95%	100.00%
MAR'88	2.20%	0.59%	2.73%	0.90%	5.76%	24.58%	63.24%	100.00%
APR'88	14.41%	4.11%	2.32%	0.88%	4.81%	22.58%	50.89%	100.00%
MAY'88	38.84%	5.04%	3.15%	0.50%	5.03%	29.56%	17.88%	100.00%
JUN'88	35.21%	0.01%	3.74%	0.35%	5.11%	33.02%	22.56%	100.00%
JUL'88	44.76%	0.43%	3.56%	0.93%	5.43%	32.57%	12.33%	100.00%
AUG'88	50.41%	0.91%	3.64%	0.17%	5.76%	29.27%	9.84%	100.00%
SEP'88	52.93%	2.41%	3.04%	0.98%	6.33%	28.30%	6.00%	100.00%
OCT'88								
NOV'88								
DEC'88	52.05%	0.58%	3.29%	0.78%	6.24%	31.76%	5.29%	100.00%
JAN'89	51.05%	1.00%	3.04%	0.49%	5.64%	20.56%	18.21%	100.00%
FEB'89	50.29%	0.59%	2.69%	0.93%	6.78%	24.08%	14.64%	100.00%
MAR'89	56.70%	0.42%	2.55%	0.13%	6.52%	25.18%	8.51%	100.00%
APR'89	65.40%	0.54%	2.89%	1.07%	6.17%	23.58%	0.35%	100.00%
MAY'89	61.96%	0.33%	2.44%	0.13%	4.27%	25.34%	5.53%	100.00%
JUN'89	46.95%	0.26%	3.10%	0.97%	4.62%	41.59%	2.51%	100.00%
TOTAL	44.05%	1.26%	3.03%	0.62%	5.59%	27.95%	17.50%	100.00%
DEC'88-JUN'89	54.91%	0.53%	2.86%	0.64%	5.72%	27.63%	7.73%	100.00%

DEPARTMENT OF MINES AND ENERGY
CALCULATION SHEET

File Number

Sheet 1 of 1

Calculator L. McDonough

Date 14-8-89

ATTACHMENT - PREDICTED ETHANE FUEL CONSUMPTION

CURRENT CONSUMPTION (Dec '88 - Jun '89)

Moomba Fuel & Flare	=	3·4 %
Port Bonython	=	6·4 %
TOTAL		9·8 %

FUTURE CONSUMPTION

→ reduce Port Bonython by 25 % = 6·4 × (1 − 0·25)
= 4·8 %

⇒ FUTURE ETHANE CONSUMPTION = 3·4 % + 4·8 % = 8·2 %

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Appendix C

ECONOMIC MODEL REVIEW

The accuracy of the economic model was checked with the actual 1988 expenditures and royalty payments. Into the model were entered the actual values for :

SALES

Sales Gas = 247 PJ
Propane = 348514 tonnes
Butane = 174591 tonnes
Condensate = 526154 tonnes
Crude = 1145797 tonnes

PRICES[3]

Sales Gas = $1.67/GJ
Propane = $165.89/Tonne
Butane = $160.92/Tonne
Condensate = $US15.13/BBL = $AUS175.55/Tonne
Crude = $US14.36/BBL = $AUS154.33/Tonne

REVENUES

Sales Gas = $311 Million
Propane = $58 Million
Butane = $28 Million
Condensate = $92 Million
Crude = $177 Million

---

3. All prices are average 1988 price, calculated as the total 1988 sales volume divided by the total 1988 sales revenue.

Table C.1: Wells Drilled, Completed and Connected in 1988

Type of Wells	Number Drilled	Number Completed	Number Connected
Exploration Wells	35	17	0
Appraisal Wells	35	27	10
Development Wells	9	9	5

Number of Online Gas Wells	238
Number of Online Oil Wells	172

Using this input data, the post wellhead Operating and Capital expenditures and royalty payment for 1988 were forecast and compared to the actual values :

Table C.2: Comparison of Model & Actual 1988 post wellhead OPEX, CAPEX & Royalty

	Model ($ Million)	**Actual ($ Million)**
Operating Expenditures :		
Upstream	106	108
Downstream	44	41
Capital Expenditures :		
Upstream	27	27
Downstream	5	3
Upstream Credit Foncier :		
Upstream	172	171
Downstream	84	83
Royalty Payment :	24.93	25.34

As seen in the preceding table, the economic model forecast to within an acceptable accuracy and therefore can be considered reliable.

Operating and Capital Costs [4]

Lifting Costs ($1988) :

Fixed Gas Well cost = $7,420 /online well/yr
Thru-put gas cost = $32,722/Bcf raw gas
Fixed Oil Well cost = $74200/online oil well/yr
Thru-put oil cost = $9.92/Tonne

All of these costs were obtained from PMA report No. 083 of August 1986 entitled "COOPER BASIN UNIT GAS PRICING STUDY" and adjusted by matching the actual expenditure of 1987 with the model's forecast.

Field Operating Costs ($1988) :

Satellite cost = $21,200/online well/yr
Satellite thru-put gas cost = $26,489/Bcf of raw gas
Satellite thru-put oil cost = $5.03/Tonne
Compression operating cost = $225/Horsepower

The per online well cost was estimated from the average of the PMA report No. 083 Major and Minor satellite operating costs, $300,000 & $600,000 respectively (1985 $) inflated to 1988 $ and divided by 25 which was estimated to be the average number of on-line wells through each satellite during 1985.
The thru-put and compression costs were also obtained from the PMA report.

Moomba Plant Operating Costs ($1988) :

CO2 Plant

Fixed cost = $3,800,000/yr
Thru-put cost = $28,000/Bcf of raw gas

Liquid Recovery Plant

Fixed cost = $5,000,000/yr
Thru-put cost
= $6,148/Bcf of raw gas
=$5.34/Tonne of Condensate & Crude
=$7.56/Tonne of LPG

Again, these costs were obtained from the PMA report and inflated to 1988 $.

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4. All costs are calculated in 1987 dollars, inflated to 1988 dollars, assumed to remain constant to 1989, and inflated by CPI thereafter.

Pt. Bonython Operating Costs ($1988) :

Thru-put cost for each component
- Crude = $19.50/Tonne
- Condensate = $19.50/Tonne
- Propane = $15.00/Tonne
- Butane = $15.00/Tonne

These costs were revenue apportionments of the total annual operating expenditure (excluding cost of depreciation and interest) acquired from the 1986 biannual royalty reports.

Overheads ($1988) :

<u>Moomba Overheads</u>

General Facilities:
- Fixed cost = $20,000,000/yr
- Variable cost = $20,000/on-line well/yr

Adelaide Facilities:
- Fixed cost = $4,000,000/yr
- Variable cost = $14,000/on-line well/yr

These were obtained from the PMA report and inflated to 1988 $.

<u>Pt Bonython Overheads</u>

General and Adelaide Facilities:
- Crude = $1.87/Tonne
- Condensate = $1.75/Tonne
- Propane = $1.41/Tonne
- Butane = $1.50/Tonne

The Moomba overheads were acquired and adjusted from the PMA report where as the Pt Bonython overheads were estimated from the 1986 biannual royalty report data as for the Pt Bonython operating costs.

Appendix D

ECONOMIC MODEL UPDATE

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c:\udd\oarmc\newroy\update.spr

The economic models developed in 1988 have been updated to accommodate for the introduction of Queensland gas to supplement sales gas supply, and to account for the consumption of raw gas as field fuel. An adjustment was also made so that the only revenue assessable for royalty purposes is that derived from sales of SA products only.

1. <u>Queensland Gas</u>

   The model has been updated to accommodate the Queensland sales gas stream. As a first pass however, it has been decided to ignore this stream for royalty calculation purposes. In operational terms it has been assumed that the toll for processing Queensland gas exactly equals the costs incurred by Queensland gas. Sensitivities will be run to test the effect of this assumption.

2. <u>Complications Arising from Queensland Gas</u>

   A brief discussion of the complications arising from the introduction of Queensland gas in calculating the royalty follows.

   a. The contract is expected to be for 30 PJ/yr of sales gas. However, after some liquids knock-out in Queensland, the raw gas will be processed at Moomba. The problem is in determining the the amounts of raw gas and liquids that should be attributed to the annual sales gas quantity. (OEP consultants report contains an estimate of the raw gas stream to Moomba).

   b. The royalty agreement must be set up to ensure that Santos do not deduct the plant operating costs attributable to Queensland gas from the assessable revenue. As a first pass, it will be assumed that the Queensland gas is simply ignored in the royalty calculations. As a consequence, the estimate of plant operating costs will be less than the actual costs. The assessable revenue will be slightly underestimated, as the fixed operating costs under this scenario are entirely attributed to the SA operation. The sensitivity to this assumption will be assessed.

A refined method would be to calculate the total operating costs including those due to the Queensland gas. In this case, revenue derived from Queensland gas would not be assessable for royalty. In this case however, the SA Producers would charge a toll on the Queensland gas, which is designed to cover the operating costs of the field. In this case, the total operating cost minus the toll on Queensland gas would be deductible for royalty purposes.

It should be noted that these points highlight potential problems in determining the actual royalty payable to SA as a consequence of the introduction of Queensland gas. There will be genuine problems in establishing which saleable products are sourced in Queensland and which are sourced in SA. There is plenty of scope for imaginative accounting by Santos such that the regime adopted to assess royalty is unfavourable for the State. Negotiations should proceed carefully in this area.

3. Field Fuel Adjustment

Also, the field fuel factor has been incorporated into the model to reduce the raw gas flow through the plant. This is required as previously the full raw gas stream throughput had been used to estimate plant operating costs. It had been overlooked that the raw gas entering the plant is reduced by the field fuel consumption. The full raw gas stream is required however, to calculate the field operating costs.

The operating cost calculations have been updated to account for this refinement. The lifting costs and satellite costs are based on the full raw gas stream, while the CO_2 plant and LRP costs are based on the reduced raw gas throughput.

These adjustments make little difference to the model while no Queensland gas is supplied. It is important to include these corrections however, as it is not good practice to allow the model to contain artificial distortions which may mask real distortions in future runs.

4. Revenue Adjustment

The model was adjusted so that the only revenue assessable for royalty purposes is that derived from sales of SA products only.

5. Oil Units Adjustment

The units in which the oil production figures are included in the model has been reset to barrels. This is because both the oil production forecast and the oil price data is in barrels.

6. Operating Costs Adjustment

Following a review of the 1988 royalty return, MM has adjusted his estimate of operating cost factors. The adjustments made are listed below :

- compressor opex
- CO_2 plant opex
- LRP fixed costs
- general facilities opex at Moomba and Adelaide
- Port Bonython stream operating costs

7. 1989 Gas Price Adjustment

During the presentation made on 21/9/89, it was brought to our attention that the gas price used in the runs for the presentation should have been $1.86/GJ rather than $1.83/GJ. This anomaly arose from the fact that we had assumed a CPI of 6% rather than using the actual CPI of 7.2%. This has since been rectified.

Appendix E

NEW ROYALTY LIQUIDS PRICING SCENARIO

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c:\udd\oarmc\newroy\price.spr

The crude and LPG prices for the new royalty predictions have been updated.

1. <u>Crude Oil</u>

   The crude oil price prediction is taken from the ABARE "1989 Outlook for Australian Mineral Resource Exports to 2000". The price is quoted in 1988 Australian dollars. The 1988 price used is $20.20/bbl and thereafter assumes an average annual percentage rate of growth of 2.2%.

   For our purposes, the oil price is required in 1989 dollars. The ABARE prediction is therefore inflated by the 1988 CPI of 7.2%.

   The ABARE forecast is only to the year 2000. The price after 2000 was increased by the annual rate of growth assumed by ABARE for their forecast to 2000.

   The crude oil price forecast in constant 1989 Australian dollars is shown in the Table 1.

2. <u>LPG Price</u>

   The ABARE forecast could not be used for LPG prices as it for export prices only. Domestic LPG prices are significantly higher than those realized on the international market. For this reason the average LPG price realized from all sales in 1988 was used as the base for the prediction rather than that supplied by ABARE. This was subsequently increased by the ABARE prediction of growth of 2.3% and then inflated to constant 1989 Australian dollars by applying the inflation 1988 average inflation rate of 7.2%.

The average LPG price for 1988 was approximately \$165/tonne. The underlying assumption in this prediction is that the ratio of domestic to international LPG sales will remain at 1988 levels for all time, as will the LPG price ratio.

The LPG oil price forecast in constant 1989 Australian dollars is shown in the Table 2.

Table 1

CRUDE OIL PRICING SCENARIO

From ABARE – "1989 Outlook"

Assume 1988 inflation rate	=	7.20%
Assume average annual percentage rate of growth (from ABARE)	=	2.20%

year	Constant 1988 dollars $AUS/bbl	Constant 1989 dollars $AUS/bbl
1988	20.20	21.65
1989	19.00	20.37
1990	20.40	21.87
1991	21.00	22.51
1992	21.50	23.05
1993	21.90	23.48
1994	22.60	24.23
1995	23.00	24.66
1996	23.50	25.19
1997	24.30	26.05
1998	24.80	26.59
1999	25.70	27.55
2000	26.20	28.09

Note : Post 2000 prices inflated at 2.2%
in real terms.

Table 2

LPG PRICING SCENARIO

Assume average LPG price in 1988 (Import + Export) – from 1988 Royalty Returns	=	165	$AUS/t
Assume 1988 inflation rate	=	7.20%	
Assume average annual percentage rate of growth (from ABARE)	=	2.30%	

year	Constant 1988 dollars $AUS/t	Constant 1989 dollars $AUS/t
1988	165.00	176.88
1989	168.80	180.95
1990	172.68	185.11
1991	176.65	189.37
1992	180.71	193.72
1993	184.87	198.18
1994	189.12	202.74
1995	193.47	207.40
1996	197.92	212.17
1997	202.47	217.05
1998	207.13	222.04
1999	211.89	227.15
2000	216.77	232.37

Note : Post 2000 prices inflated at 2.3%
in real terms.

Appendix F

FORECAST OIL WELLS ON-LINE FOR ROYALTY PREDICTION

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c:\udd\oarmc\newroy\wells.spr

Table 1 presents a forecast of the number of oil wells on-line until the end of 2006. This forecast will be incorporated in the new royalty runs.

This forecast is necessary as there is no formal Santos forecast. The forecast is based on the Santos forecast of oil production by block, the June 1989 Block Oil Production figures and the 1989 Santos Development Plan.

The number of wells available or on-line as at June 1989 was extracted from the Block Oil Production Figures for each Block with the exception of the Patchawarra Central Block. The data for Patchawarra Central is taken from a forecast in the 1989 Development Plan. It was assumed that this number of wells on-line would remain constant for the duration of oil production from that block. The prediction of the duration of oil production from each block was taken from 1989 Development Plan. The total number of wells on-line for each year was then calculated.

The assumption that all the wells on-line in 1989 remain on-line for the duration of production from that block may be slightly conservative, though this is not considered to be a serious problem. In actual practice there will be a general production decline in all wells down to an economic limit. Although it is true that some wells will come off-line prior to the end of the life of the block, it is equally true that more wells will be brought on-line to sustain production. The approach taken here is the best approximation to this phenomenon.

It should be noted that for both the Patchawarra Central and Toolachee Blocks, the injection wells involved in the respective E.O.R. projects were included as on-line wells. This is because there is no other way of attributing costs to these wells at present.

The Santos forecast of oil production is presented here for convenience in Table 2. This is extracted from Table 4 of the Santos 1989 Preliminary Development Plan.

Table 1

FORECAST WELLS ON-LINE

year	Lake Hope Block	Toolachee Block	Merr/ Inn Block	Napp/ Murt Block	Murta Block	Moomba Block	Patch. Central Block	Total Wells
1989	11	22	15	35	17	16	53	169
1990	11	22	15	35	17	16	56	172
1991	11	22	15	35	17	16	56	172
1992	11	22	15	35	17	16	54	170
1993	11	22	15	35	17	16	55	171
1994	11	22	15	35	17	16	55	171
1995	11	22	15	35	17	16	55	171
1996	11	22	15	35	17	16	53	169
1997	11	22	15	35	17	16	40	156
1998	11	22	15	35	17	16	40	156
1999	11	22	15	35	17	16	40	156
2000		22	15	35	17		40	129
2001		22	15	35	17		34	123
2002			15	35	17		34	101
2003			15	35			34	84
2004			15	35			34	84
2005			15	35			34	84
2006			15	35			34	84

c:\udd\oarmc\newroy\oil.wkz

Notes :

1. Block oil wells for 1989 are the number of wells on-line or available during June 1989. These numbers are estimated from the June 1989 Block Oil Production Figures.

2. The Unit oil wells, (i.e. Patchawarra Central), are taken from the 1989 Development Plan. Injection wells are included in the total.

3. The Toolachee Block wells include four injectors on the Dullingari Murta Waterflood Project.

4. It is assumed that all wells currently on line will remain on production until production from that block ceases.

Table 2

ACTUAL SANTOS OIL FORECAST

From preliminary Santos 1989 Development Plan

year	Total Crude (kbbls)
1989	8977
1990	7240
1991	5505
1992	4292
1993	3456
1994	2850
1995	2322
1996	1943
1997	1682
1998	1461
1999	1301
2000	1121
2001	891
2002	775
2003	685
2004	599
2005	524
2006	451

Appendix G

ECONOMIC MODEL INPUT DATA FROM TARDIS

This Input Data is kept in File D:\TARDIS\ECOINPUT.WK1 (MM's computer)

1. **Raw Gas :**

   The raw gas stream was obtained from the NEW TARDIS run and the portion of raw gas attributable to field and plant fuel was included. The conversion factor from tonnes of raw gas to bcf is 28051.44 Tonnes/Bcf.

2. **Sales Gas :**

   The NEW TARDIS sales gas forecast conversion factor
   from tonnes to bcf is 20139.03 Tonnes/Bcf
   and from bcf to petajoules is 1.051396 PJ/Bcf.

3. **Ethane :**

   The ethane conversion rate from tonnes to petajoules is 51.92 MJ/kg.

4. **LPG & Condensate :**

   The propane, butane and condensate forecasts from the NEW TARDIS run were in tonnes and entered into the economics program in these units.

<u>Wells Drilled, Completed & Connected</u>

Exploration & Appraisal Wells :

From the NEW TARDIS run the drilling and connection of these wells was forecast. 50% of the exploration wells and 75% of the appraisal wells drilled were assumed successful and thus completed.

Development Wells :

Due to the nature of TARDIS, in the first year it is run it assumes no fields are on-line and so it commences bringing on wells already connected in its gas fields in order of field sequence. However before it brings on the next field it drills up the previous one to its economic limit, therefore it fully drills up fields to meet the deliverability demand rather than bringing on already connected wells from other fields. Hence in the first year of the TARDIS run an unusually high number of 82 development wells were drilled in zone 1, to represent this drilling more realistically the development wells were evenly spaced over the first nine years.

On-line Wells :

TARDIS does not drill multiple completions, rather multiple reservoirs in a field would be individually drilled. Therefore the number of annual wells actually required are overstated by TARDIS and this was accounted for by de-rating them by the average of the ratios of the actual number of wells on stream to the number of completions on stream for 1987 and 1988. This ratio was evaluated as 0.86.

The TARDIS forecast of on-line wells also included solution gas wells. In reality these are oil wells and their operating costs need to be accounted for separately to the gas wells, therefore the solution gas wells were separated and included in the total on-line oil well category. The solution gas reserves of four major oil fields were included in TARDIS and the number of wells forecast for these fields were as follows:

1. TIRRAWARRA 43 wells from 1989 to end of 2018
2. MOORARI 5 wells from 1989
3. BROLGA 4 wells from 1989
4. FLY LAKE 2 wells from 1989 to end of 2004