



A reference under Article 15 of the Gas (Northern Ireland) Order 1996

Phoenix Natural Gas Limited price determination

Presented to the Northern Ireland Utility Regulator
28 November 2012

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Contents

	<i>Page</i>
Summary	1
Report.....	1-1
Section 1: Introduction	1-1
Section 2: Background	2-1
Section 3: The reference.....	3-1
Section 4: Gas customers	4-1
Section 5: Outperformance	5-1
Section 6: The 1999/2000 capex deferrals.....	6-1
Section 7: Rate of return for PNGL.....	7-1
Section 8: Implications for regulatory certainty and cost of capital.....	8-1
Section 9: Evaluation and findings	9-1
Section 10: Adjustments to the financial model and recommendations	10-1
 <i>Appendices</i>	
A: UR's notice of reference to the CC.....	A1
B: UR's statutory duties	B1
C: Evidence on outperformance from submissions	C1
D: Deferred capex.....	D1
E: Arguments by PNGL and UR regarding the risks faced by PNGL in 1996	E1
F: Stylized illustration of asymmetric risk	F1
G: PNGL's arguments on the cost of capital allowed to mature Great Britain utilities and potential comparators in 2006	G1
H: Financeability	H1
I: Third party submissions in response to our provisional decision	I1
 Glossary.....	 Glos1

Contents

	<i>Page</i>
Summary	4
Report.....	1-1
1. Introduction	1-1
2. Background.....	2-1
Introduction	2-1
PNGL	2-1
UR.....	2-3
Current structure of the natural gas industry in Northern Ireland	2-5
Background to the Northern Ireland gas industry.....	2-7
Development of PNGL’s business	2-8
Background to regulation	2-11
PNGL12	2-16
3. The reference.....	3-1
Legal framework.....	3-1
The Order	3-1
The licence	3-1
Price control reviews.....	3-2
The reference	3-3
The statutory duties	3-3
The CC’s approach	3-4
4. Gas customers	4-1
Introduction	4-1
The PNGL Licensed Area	4-1
Protecting consumer interests	4-4
UR	4-4
Consumer Council Northern Ireland.....	4-4
PNGL’s consumer responsibilities	4-4
Customer service standards	4-4
Safety obligations on consumers and PNGL.....	4-5
Increasing the availability of natural gas in Northern Ireland.....	4-6
Costs of energy	4-10
Fuel poverty.....	4-10
The case for switching to natural gas	4-12
Industrial and commercial customers.....	4-15
Converting to natural gas.....	4-16
Fluctuations in the cost of fuel.....	4-19
Cost and impact of UR’s price control	4-20
Questions raised by CCNI	4-20
Advertising, marketing and PR.....	4-21
PNGL does not operate an asset register	4-21
Service standards.....	4-21
Planning the infill of PNGL’s existing network	4-22
5. Outperformance	5-1
Introduction	5-1
Past treatment of outperformance	5-2
Treatment of outperformance.....	5-2
Sources of historic outperformance	5-4
Historic outperformance	5-6
Opex and capex outperformance.....	5-8
Other categories of outperformance.....	5-8
Accumulation of outperformance into the TRV	5-9
UR’s proposed decision on historic outperformance in PNGL12	5-10
PNGL response.....	5-11

Issues relating to outperformance	5-12
Assessment of historic outperformance.....	5-13
Arrangements for the treatment of past outperformance.....	5-13
Good regulatory practice.....	5-14
Efficiency of outperformance.....	5-18
Other issues relevant to the overall public interest	5-29
Whether there had been previous sharing of outperformance.....	5-29
Exceptional circumstances	5-32
Prior indications that historic outperformance would be revisited	5-33
Issues relating to WCA outperformance and volume underperformance	5-37
Our assessment.....	5-38
6. The 1999/2000 capex deferrals	6-1
Introduction	6-1
Background.....	6-2
The reasons for the 1999/2000 capex deferrals.....	6-2
The general treatment of deferred capex by UR in its PC02 and PC03 charge control decisions.....	6-3
PNGL and UR's arguments on the 1999/2000 capex deferral projects	6-4
UR	6-4
PNGL.....	6-5
Our assessment of the treatment of 1999/2000 capex deferrals.....	6-6
The original capex allowances for the 1999/2000 capex deferrals	6-7
Capitalized financing and management fees.....	6-9
Capitalized financing.....	6-9
Management fee.....	6-14
Conclusion.....	6-15
7. Rate of return for PNGL	7-1
Introduction	7-1
Our view	7-4
Rate of return in 1996.....	7-5
Our view	7-6
Rate of return in set as part of the 2007 determination	7-10
Our view	7-11
Changes to the risk profile of PNGL due to the regulatory framework introduced in 2007	7-11
Rate of return in 2012/13.....	7-21
8. Implications for regulatory certainty and cost of capital.....	8-1
Introduction	8-1
PNGL's views on the implications of UR's proposals to reduce the TRV	8-2
Wider costs to other industries.....	8-4
PNGL's evidence on debt premiums.....	8-5
UR's response.....	8-6
Effect on other companies and industries	8-8
Evidence on effects on investment and cost of capital.....	8-9
Credit ratings agencies' views.....	8-10
Third parties' views	8-13
Additional third party points raised in response to the provisional determination	8-19
PNGL's submissions on its own willingness to invest.....	8-19
Assessment	8-20
The extent to which regulatory uncertainty may arise	8-21
The effect of an increase in regulatory uncertainty.....	8-22
Evaluation of evidence on premium for PNGL's debt	8-24
Effect on regulatory uncertainty of a change in the rate of return	8-26
9. Evaluation and findings	9-1
Introduction	9-1
Background.....	9-2

Discussion of issues.....	9-4
Opex and capex allowances and other non-disputed matters	9-4
Rate of return.....	9-5
Elements of the TRV	9-9
Outperformance.....	9-10
Deferred capex	9-13
1999/2000 capex deferrals	9-14
Whether full inclusion of outperformance in the TRV is against the public interest	9-17
Objective measures of price levels.....	9-19
Conclusions on whether the current arrangements for inclusion of outperformance in the TRV are against the public interest.....	9-21
Proposals to remove elements of the TRV and other actions to reduce prices	9-25
Expectations and regulatory stability.....	9-26
The extent of future network expansion	9-28
Conclusions on proposal to remove elements of the TRV	9-29
Final determination.....	9-29
Licence modifications.....	9-29
Financeability.....	9-30
10. Adjustments to the financial model and recommendations	10-1
Overview.....	10-1
Modelling changes	10-1
Modelling changes to implement our determination on the 2012 TRV adjustment ..	10-2
Working capital	10-2
Costs of the inquiry	10-2
PNGL's allowed revenues for 2012 and 2013	10-5
Other suggested or possible changes that we did not implement	10-5
Actual data.....	10-5
Efficiency assumptions	10-6
Use of COPI index	10-6
Depreciation assumptions.....	10-7
Working capital	10-7
Recommendations	10-7
Timing of cash flows	10-8
Connections incentives.....	10-8
Other recommendations	10-9

Summary

1. The Northern Ireland Authority for Utility Regulation (the Utility Regulator, UR) issued a Price Control Determination for 2012 and 2013 for Phoenix Natural Gas Ltd (PNGL) on 10 January 2012. On 6 February 2012 PNGL issued a Disapplication Notice and rejected UR's Price Control Review Determination. PNGL also rejected UR's intention to modify PNGL's licence by reducing the total regulatory value (TRV) specified in the licence.
2. On 28 March 2012 UR made a reference to the Competition Commission (CC), requiring the CC to investigate and report on whether the price control conditions operate or may be expected to operate against the public interest and, if so, whether the adverse effects could be remedied or prevented by modifications of the licence conditions. In determining for the purposes of this reference, whether any particular matter operates against the public interest, we are required to have regard to the same duties as apply to the Department of Enterprise, Trade and Investment (DETI) and to UR. The Energy (Northern Ireland) Order 2003 (the Energy Order) states that the principal objective of DETI and UR in carrying out their respective gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and to do so in a way that is consistent with the fulfilment by UR pursuant to Article 40 of the Gas Directive¹ of the objectives set out in paragraphs (a) to (h) of that Article. In undertaking our inquiry we have applied the public interest test with due regard to the duties imposed by Article 14 of the Gas Order and Article 40 of the Gas Directive.
3. PNGL is the owner and operator of the natural gas distribution network in the Greater Belfast Area and Larne (its Licensed Area). PNGL is now owned by private equity group Terra Firma. In June 2012, Phoenix sold its gas supply businesses to SSE plc (Airtricity).
4. In 1996 PNGL was given a 20-year licence to convey gas and to supply gas in the Licensed Area. There was no existing natural gas network in Northern Ireland. The licence and regulatory structure reflected the unusual circumstances of the greenfield investment:
 - (a) Revenue recovery was profiled over a 20-year period to reflect the fact that being a new build it would take time for volumes to grow to a sustainable level. The licence included formulae to capitalize negative cash flows to be recovered later in the 20-year period.
 - (b) A fixed 8.5 per cent real pre-tax return on cash flows over 20 years was allowed.
 - (c) The licence set output targets requiring PNGL to build the gas network within its Licensed Area in accordance with a defined timetable.
5. UR regulates the gas industry in Northern Ireland including licensing operators and suppliers. It regulates PNGL's distribution prices. In 1999, three years into the recovery period, UR issued its first price control determination (PC01) for PNGL covering 1996 to 2001. The second price determination (PC02) in April 2002 covered the period 2002 to 2006. During the PC02 period it was realized that it would be difficult for PNGL to recover its investment costs within its licence period. Prices would have to rise very substantially as the uptake of gas by customers was below

¹ Directive 2009/73/EC of the European Parliament and the Council of 13 July concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

the original forecasts and because of the accumulation of deferred revenues. Following negotiations and consultations a determination was reached in 2007 whose key components were:

- (a) an extension of the cost recovery period in the licence from 20 to 50 years;
 - (b) the introduction of a price control mechanism based explicitly on a regulated asset value (RAV) and the determination of an opening asset value (OAV) which was incorporated into the licence;
 - (c) the establishment of a depreciation profile, which determined the period over which PNGL could recover the TRV (and any new capital expenditure (capex)), and the introduction of a profile adjustment (the mechanism to profile the recovery of revenue in line with the expected growth in volumes over time); and
 - (d) a reduction in the rate of return from 8.5 to 7.5 per cent through to the end of 2016 (at which point it would be reviewed in line with best regulatory practice at the time).
6. In addition, PNGL's price control moved to a revenue cap, and PNGL's transmission business was mutualized and sold. The scope of the relevant licence covering PNGL was therefore reduced.
 7. The OAV comprised a number of elements: 54 per cent represented PNGL's past investment in developing the network that had not yet been recovered from customer payments; 21 per cent represented the capitalized value of the accumulated under-recoveries of deferred revenues; and 25 per cent represented the capitalized value of unspent allowances (ie outperformance arising on operating expenditure (opex), capex and working capital allowances (WCA), volume underperformance, and deferred capex. These are sums that PNGL was granted as allowances and which it could recover from customers, but which it had not spent).
 8. The main change proposed by UR in the 2012 charge control compared with the 2007 charge control involved a reduction of the TRV of around £75 million (the 2012 TRV adjustment). This consisted of an adjustment to share historic outperformance and remove deferred capex (the 1999/2000 capex deferrals) which had been included in the 2007 OAV and which had accrued in the period 1996 to 2006. UR said that deferred capex referred to allowances for projects PNGL had yet to complete or which were completed later than originally anticipated. It said that it had formed the opinion that the company should not retain the benefit of a failure to deliver assets or the delivery of assets later than originally scheduled. UR also proposed only to allow PNGL to retain the historic outperformance sum in its TRV until the end of 2011, by which time it said PNGL had enjoyed five years of reward (by way of depreciation and return from its inclusion, amounting to around £35 million), and then to remove the residual value of outperformance remaining in the TRV.
 9. UR said that it was not in the public interest for PNGL to earn 40 years of return on unspent allowances. It argued that the 2012 TRV adjustment was part of its process of moving to a regulatory asset base (RAB)-based regulatory system, that PNGL had already been rewarded for historic outperformance in a way consistent with normal practice under a RAB-based system, and that not to make an adjustment would over-reward PNGL and be contrary to the interests of customers. It said that the point was not to deliver a benefit to customers for its own sake, but to strike the balance required by its duties.

10. PNGL rejected these proposals. It said that the 2006 TRV formed part of what it termed the 2006 'agreement' on a package of modifications. It said that this effectively recorded an agreed approach to sharing value between PNGL and its customers, present and future. PNGL said that the 2006 'agreement' (and in particular the 2006 TRV) was subsequently incorporated into PNGL's licence and was intended to 'draw a line under the past'. PNGL said that there was no defect in the 2006 'agreement' and no new information had arisen since it was concluded that would suggest otherwise. PNGL said that the 2012 TRV adjustment substantially and retrospectively reduced the 2006 TRV value that had been embedded within PNGL's licence. It said that this reopening of the 2006 'agreement' caused considerable regulatory uncertainty, severely undermined investor confidence and changed the basis on which PNGL had taken its investment decisions since 2006. This was to the detriment of both PNGL and its customers, and to PNGL's task of introducing a natural gas infrastructure to Northern Ireland.
11. Our investigation, during which we have reviewed the evidence of UR's 2012 determination in its entirety, has led us to conclude that the following issues are those that are of most concern for us and require investigation to determine whether they operate or may be expected to operate against the public interest:
 - the amounts included in the TRV in respect of opex and capex outperformance, and deferred capex; and
 - the rate of return that PNGL should recover on its investment.
12. Those two issues were the main, but not only, focus of our inquiry. We also considered a number of secondary issues, in particular whether PNGL has been funded twice for the same expenses in respect of business rates.
13. There are also other issues that are not in dispute between UR and PNGL as to whether the price controls need some modification. In particular, we reviewed the proposed opex and capex allowances, although there was no evidence proffered that the allowances were inappropriate and, in any event, there was no substantive disagreement between the parties on this point. Therefore we consider that the existing opex and capex allowances operate or may be expected to operate against the public interest and that they need to be revised. Our review showed no reason to believe that the proposed allowances were out of line with what was required for PNGL properly to undertake its activities and invest in the distribution network.
14. UR has also concluded that change is needed on a variety of further issues which have not been disputed by PNGL, such as amendments to PNGL's connection incentives. We also accept that the current arrangements on these issues need to be revised to suit current circumstances and so conclude that the current arrangements are or may be expected to operate against the public interest and should be revised as proposed in PNGL12.
15. We then considered whether the disputed aspects of the current arrangements are against the public interest.
16. We found no reliable or practicable method for evaluating whether or not current distribution prices are reasonable or excessive based on an objective measure that would help inform the assessment of whether the arrangements are in the public interest.
17. We did not find any examples of errors in the way outperformance and deferred capex had been calculated and applied, with one exception: in regard to allowances

for the treatment of business rates we note that there will be potential for PNGL to be funded twice for the same business rates expenses. We do not consider that funding this twice is in the public interest. We determine that an adjustment should be made to rectify this problem.

18. UR did not propose to revise PNGL's rate of return in its PC2012 determination. However, during the course of our investigation it suggested that if we did not accept UR's other proposals, we should consider whether the rate of return should be reduced.
19. We observe that the forward-looking weighted average cost of capital (WACC) for PNGL in 2012 and 2013 is likely to be lower than the 7.5 per cent allowed real rate of return (set in the 2007 determination to apply to 2016), because PNGL is increasingly mature and the regulatory framework has become more standardized. On the other hand, we note that revenue continues to be deferred into the future, that elements of the regulatory regime are still developing and that there is a need to ensure continued investment for the future development of the network. We are not satisfied that it was not in the public interest to embody that rate in PNGL's price control, taking into account the project-specific risks that it assumed in its greenfield development of the gas distribution network. Rather, there are good reasons to think the maintenance of a project risk premium is consistent with both the future and past project risks faced by PNGL.
20. The conclusion that we have reached is that we cannot say that a fixed, real, rate of return of 7.5 per cent is against the public interest. It remains the case that a project risk premium should be allowed to supplement the WACC in 2012 and 2013. We note that matters will be considered again in the course of future price reviews, and necessarily in 2016, when the period of application of the 7.5 percent rate comes to an end.
21. Turning to outperformance, under the 1996 licence and in the regulatory framework applied under PC01 and PC02, until 2006 PNGL was entitled to receive and retain 100 per cent of its outperformance. The retention by PNGL of outperformance in its entirety contrasts with UR's current view that outperformance should be shared between PNGL and its customers. PNGL was unable to recover this outperformance at the time it accrued.
22. We found that the treatment of outperformance in successive price controls has been to allow PNGL to recover and retain outperformance over the long term. We believe that this reflects a recognition by the regulator that, prior to the current price control review (and in addition to the purpose of incentivizing PNGL to pursue efficiencies and cost reductions in its operations), development of the network was best served by allowing PNGL to obtain a benefit from outperformance even if that benefit could not be realized as it arose. We found no basis for identifying whether any significant element of historic outperformance was inefficient, or what proportion this would be.
23. We conclude that the inclusion of historic outperformance in the TRV does not operate or may not be expected to operate against the public interest. The inclusion of outperformance was an important incentive element in a system of risks and rewards that has provided benefits to consumers. The benefits to customers through development of the network, and through the continuing development of the network (which could be impaired if the perception of regulatory stability was harmed), justify the costs and it is right that customers who benefit should pay for the costs of that network, part of which is the cost of the risk taken on by PNGL.

24. Turning to deferred capex, we addressed two categories: deferred capex that is included in the TRV under the general classification of outperformance, and separately a set of specific capex projects that were deferred from 1999/2000 (following a change in PNLG's network development strategy).
25. With regard to the general deferred capex category, the information we have available is not sufficient to establish whether or not these deferrals arose as a result of genuine efficiencies, or benefited customers by better timing or redeployment of capex (such as running pipes to areas with the highest likelihood of demand rather than sticking to a fixed roll-out plan), all of which are positive, or whether they simply allowed PNLG to gain a financial benefit from delaying investment so that it could earn a return before an investment was actually made. UR did not undertake an appraisal of whether deferrals were efficient, other than for certain specific capex deferrals that UR explicitly considered efficient.
26. We note that the regulatory regime between 1996 and 2006 allowed PNLG to benefit from capex deferrals, and this contributed to PNLG's expectations of how it would be rewarded and helped shape its investment strategy. We think that these rules have and continue to serve as a heightened incentive mechanism (which increases the potential rewards available) and so indirectly increases the degree to which the business is resilient to the effects of risk, and thereby increased its initial willingness to incur risk. We do not consider that the inclusion of historic deferred capex (and the financing returns on these sums) in the TRV operates or may be expected to operate against the public interest.
27. In contrast to the general category of capex deferrals, for the 1999/2000 capex deferrals, we can identify specific projects and the duration of deferrals that apply. In its PC03 charge control decision, UR indicated that it would reassess the treatment of the 1999/2000 capex deferrals. A distinguishing feature is the extent of time for which these projects have been deferred. It appears to us that, given that PNLG revised its investment policy in 1999, the need for these projects in the foreseeable future has dropped away. It would appear unreasonable to offer a regulated company a return on an allowance to undertake a project that it has never undertaken and that it is not going to undertake. Therefore we consider that retention of seriously delayed, or irrelevant and superseded projects in the portfolio of intended investments is no longer appropriate and they should be removed and only reinstated when they are immediately relevant to the current strategy.
28. We also considered to what extent PNLG should be allowed to retain the capitalized financing on these sums. We consider that by 2007 it was likely to be apparent that these projects may not be required in the near future. Because these projects were identified in 2006 for review, we can conclude that from this date it was appropriate to consider these projects as not compatible with PNLG's capex strategies. Further, the application of the PC03 rules indicates outcomes consistent with our judgement that the inclusion of the 1999/2000 deferred capex projects that were not completed by the end of PC03 (and the associated capitalized financing benefits arising since 2007) are inappropriate because they operate or may be expected to operate against the public interest. Consequently we conclude that:
 - (a) for those 1999/2000 capex deferrals that were completed in PC03, no further adjustments are made; and
 - (b) for those 1999/2000 capex deferrals that were not completed in PC03, an adjustment equivalent to the retrospective adjustment mechanism that applies in PC03 should be made, ie the 1999/2000 capex deferrals that were not completed in

PC03 are removed from the TRV including the capitalized financing benefit that accrued to PNGL since 2007, but that no further adjustments should be made.

29. Overall, taking account of the purposes for which outperformance has been included in the TRV and whether those purposes are still good, and secondly, considering the interests of consumers, we do not consider that the inclusion of historic outperformance in the TRV is against the public interest, and we also conclude that, for the most part, inclusion of deferred capex in the TRV is not against the public interest. However, we have found that in the specific case of identified 1999/2000 capex deferrals where these have not been completed by the end of PC03, these sums are against the public interest. We also consider it appropriate to remove the project management allowance associated with these projects.
30. Although our conclusions on whether the current price control conditions were against the public interest meant that the TRV need not be revised (except with respect to some adjustments to deferred capex for 1999/2000 deferrals uncompleted by the end of PC03, the associated capitalized financing and management fee and an adjustment to business rates outperformance), we also considered whether the consequences of removing outperformance and deferred capex would have adverse consequences.
31. The following two considerations were important:
 - whether these actions would create a perception of regulatory instability and whether this would have a significant effect in deterring future investment and/or increase the cost of future funding of existing and additional investment in gas distribution and other regulated sectors in Northern Ireland; and
 - what the effect on future network expansion might be.
32. In line with normal regulatory practice, our view is that any revision of previous regulatory determinations should be: well reasoned, properly signalled, subject to fair and effective consultation, clear and understood, and, normally, forward-looking. We consider that some changes are more serious than others, and that to reduce ex post and without clear signalling the opening value of a RAB is a step that should not normally be taken without very good justification, and only then after an appropriate period of consultation on the proposals. In contrast to the case for the deferred capex projects from 1999/2000, a cause for concern is whether UR gave sufficient notice or sufficiently consulted on its proposal to revise the other elements of the TRV. While UR says it indicated that it intended to share historic outperformance (referring to a reference to following best practice in its 2006 consultation document), we consider that it gave no public indication in the 2007 determination (nor any indication until 2011) that it did not intend to allow historic outperformance to remain in the TRV. Any intention to revise the historic outperformance in the OAV that it may have formed appears inconsistent with its actions and statements at that time, which point more towards the OAV having been established and fixed. It is difficult to see how PNGL and its investors could have anticipated these proposals ahead of UR's consultation on the issue in 2011.
33. We consider that a reduction in the TRV, with its consequent effect on the expectations of both PNGL and its investors, can have an impact on the perception of regulatory stability and can damage investor confidence in the regulatory framework. We are not able to quantify the effects of a lack of regulatory stability, but we consider that the qualitative evidence suggests, notwithstanding the statutory position and the right of appeal, that such an effect exists and that it is not so small that it can

be disregarded. Any increase in the cost of capital would feed through into relatively higher prices to customers.

34. Possible expansion of gas supply in Northern Ireland includes extension of the network within existing Licensed Areas by PNGL and firmus energy (firmus) to infill un-supplied areas, potential incremental expansion from the existing Licensed Areas into adjacent areas, and also the development of new distribution networks. In particular, expansion to the West via a new supply pipeline is under active consideration. Additionally, it is possible that other new expansion opportunities may be identified.
35. While we cannot determine the extent of these future expansions, they are possibilities, and whether they go ahead depends on many factors (including the costs of funding expansion and investors' willingness to invest, but also factors such as the relative cost of fuels, government policy and willingness to promote expansion for economic, social and environmental reasons, and so on). However, the scale of these expansions could be large.
36. Any impact of the type outlined in paragraph 33, which reduces the extent of network expansion, or particularly the development of new supply areas in Northern Ireland, implies a large opportunity cost for future customers who would otherwise benefit from the ability to convert to natural gas. The process for the next expansion of the gas network in Northern Ireland is already under way, and the negotiation of licences and arrangements may be hampered by a belief that UR could overturn aspects of the agreement at a later date. This is consistent with what we have been told about the government objectives for the gas sector. We note that the Northern Ireland authorities said they were keen to develop a natural gas market in Northern Ireland and in particular in the West of Northern Ireland for a number of reasons, including the environmental benefits of switching to gas via reduced carbon emissions, the increased fuel choice and savings for consumers, the diversification of energy sources and to make the province more attractive from the perspective of overall business investment, including foreign investors.
37. For these reasons we consider that actions to remove historic outperformance and deferred capex could have adverse consequences in creating a perception of regulatory instability. While it is clear that prices to existing customers would reduce, we also note that there is a substantial risk that the consequences of such measures would be to reduce the willingness of investors to invest in future development of the gas network (and possibly other regulated sectors in Northern Ireland) and could increase the cost of capital applying. Therefore we consider that this could impede future gas network development which could otherwise create substantial future benefits for future customers, and could increase costs for current and future gas consumers.
38. Elements of this determination (such as revised capex and opex allowances and projections of future demand—see paragraphs 13 and 14) will have the effect of increasing prices to customers relative to the prices that would be charged. Allowing for our decisions to remove certain elements from the TRV, we estimate that the overall effect of all changes would be to increase typical charges for an average household by around £11 per year. If UR's proposals to remove historic outperformance and deferred capex in full from the TRV were accepted, we estimate that the average household charges would be around £12 a year lower than our determination. We also recognize that the higher TRV will impact on bills until 2046.
39. This is obviously an important consideration affecting current and future domestic and business customers. However, taking account of the overall public interest, including among other things drawing a balance between protecting current

customers, and ensuring the ongoing development of the industry such that future customers will benefit from the wider provision of gas, we consider that this final determination is appropriate.

Final determination

40. We conclude that the existing price control arrangements are not in the public interest and should be modified as outlined above.
41. We agree with the proposed revisions for opex and capex allowances made by UR, as well as the other changes it made in the PNGL12 determination, except for UR's TRV adjustment. We conclude that no revision should be made to the TRV, except to reflect the 1999/2000 capex deferrals that were not completed by the end of PC03 (including post-2006 capitalized financing benefits), together with an appropriate management fee of 5 per cent. We estimate this value at £8.6 million.
42. In addition, an adjustment should be made to the TRV for funding PNGL twice for the same business rates expense. We estimate this value at £5 million.
43. Under article 17(3) of the Gas Order, UR is now required to give notice of the modifications to the relevant conditions of PNGL's licence UR proposes to make for the purpose of remedying or preventing the adverse effects we have specified in our report. After considering any representations or objections made to these proposals, UR must notify the CC of the proposed modifications and of the reasons for making the modifications.
44. Under the procedure set out in the Gas Order, the CC then has four weeks in which, if necessary, to direct UR not to make some or all of the proposed modifications, and to propose different modifications, which seem to the CC requisite for the purpose of remedying or preventing adverse effects specified in the CC's report.

Report

1. Introduction

- 1.1 UR issued a Price Control Determination for PNGL on 10 January 2012. On 6 February 2012 PNGL issued a Disapplication Notice and rejected UR's Price Control Review Determination. On 28 March 2012 UR made a reference to the CC. UR's notice of reference to the CC was published on our website on 29 March 2012 and is attached to this report as Appendix A. In accordance with Article 15(1) of the Gas (Northern Ireland) Order 1996 (Gas Order) the reference provided six months for the CC to consider:
 - (a) whether the price control conditions operate or may be expected to operate against the public interest; and
 - (b) if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the conditions of licence.
- 1.2 On 13 September the CC made representations to the Regulator pursuant to Article 15A(3) of the Gas Order that there were special reasons why the report could not be made by 28 September 2012.
- 1.3 On 17 September, pursuant to Article 15A(3) of the Gas Order, the Regulator extended the period for making the report to 30 November 2012.
- 1.4 The CC published its provisional determination on 6 August 2012. On 26 October the CC undertook a further limited consultation exercise in relation to Section 3 and Section 9 of the draft final determination
- 1.5 This document and its appendices comprise our final determination on the questions which UR required us to consider. Non-commercially-sensitive versions of [written submissions](#) from the main and third parties and a [summary of the hearing](#) with The Consumer Council for Northern Ireland (CCNI) are on our website along with other relevant documents. We cross-refer to them where appropriate throughout this report.

2. Background

Introduction

- 2.1 This section sets out the background to our investigation. It outlines the development of the natural gas industry in Northern Ireland, PNGL and UR, and the background to how PNGL has been regulated including UR's past determinations.

PNGL

- 2.2 PNGL is the owner and operator of the distribution network in the Greater Belfast area and Larne (the Licensed Area), and is the larger of the two gas distribution businesses in Northern Ireland (the other business being firmus, which since 2005 has owned and operated the network off the North–West and South–North transmission pipelines). The PNGL network extends to around 3,000 km of intermediate-, medium- and low-pressure mains, which distribute natural gas throughout the Licensed Area. PNGL manages the development of both the physical network and market in the Licensed Area. PNGL is owned by private equity group Terra Firma.¹
- 2.3 PNGL's Licensed Area is shown in Figure 2.1. Its gas distribution network within its Licensed Area is shown in Figure 4.1.

¹ UR [initial submission](#), paragraphs 2.15–2.18.

FIGURE 2.1

PNGL's Licensed Area



Source: PNGL.

Notes:

1. 'Belfast' includes Duncruie, Harbour, Carryduff, Castlereagh and Dundonald.
2. 'North Down' includes Bangor, Newtownards, Hollywood, Donaghadee and Comber.

- 2.4 PNGL is the sole provider of gas distribution services in its Licensed Area, and is subject to regulation by UR, including price controls.

UR

- 2.5 UR is an independent statutory body corporate with its board appointed by the Northern Ireland Government, and it employs a body of expert regulatory staff. It is a non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries. Its statutory duties are set out in the Energy Order and the Water and Sewerage Services (Northern Ireland) Order 2006.²
- 2.6 UR's statutory duties in relation to gas are set out in Appendix B. Its principal objective in carrying out its gas functions, as set out in Article 14(1) of the Energy Order, is to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland, and to do so consistently with fulfilment of the objectives set out in Article 40 of the Gas Directive.³
- 2.7 We set out below some relevant parts of Article 40 of the Gas Directive (it is set out in full in Appendix B):

General objectives of the regulatory authority⁴

In carrying out the regulatory tasks specified in this Directive, the regulatory authority shall take all reasonable measures in pursuit of the following objectives within the framework of their duties and powers as laid down in Article 41, in close consultation with other relevant national authorities, including competition authorities, as appropriate, and without prejudice to their competencies:

- (a) promoting, in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in natural gas within the Community, and effective market opening for all customers and suppliers in the Community, and ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long-term objectives;
- ...
- (d) helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented, and promoting system adequacy and, in line with general energy policy objectives, energy efficiency as well as the integration of large and small scale production of gas from renewable energy sources and distributed production in both transmission and distribution networks;
- ...
- (f) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies in system performance and foster market integration;

² UR [initial submission](#), paragraphs 2.6–2.10.

³ Directive 2009/73/EC of the European Parliament and the Council of 13 July concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

⁴ Where the text refers to 'The Authority', UR is the current relevant regulatory authority.

- (g) ensuring that customers benefit through the efficient functioning of their national market, promoting effective competition and helping to ensure consumer protection;
- (h) helping to achieve high standards of public service for natural gas, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for customer switching.

2.8 In addition, UR must also have regard to a number of other matters set out in Article 14 of the Energy Order (see Appendix B). These include:

(2)(a) the need to ensure a high level of protection of the interests of consumers of gas;

(b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Gas Order or this Order;

(c) the need to secure that the prices charged in connection with the conveyance of gas through designated pipe-lines (within the meaning of Article 59) are in accordance with a common tariff which does not distinguish (whether directly or indirectly) between different parts of Northern Ireland or the extent of use of any pipe-line; and

(d) the need to protect the interests of gas licence holders in respect of the prices at which, and the other terms on which, any services are provided by one gas licence holder to another.

(3) In performing that duty, the Department or the Authority shall have regard to the interests of—

(a) individuals who are disabled or chronically sick;

(b) individuals of pensionable age; and

(c) individuals with low incomes;

but that is not to be taken as implying that regard may not be had to the interests of other descriptions of consumer.

2.9 UR told us that the application of its statutory duties necessitated that price control decisions should strike a balance between all of these elements, and be consistent with the duties taken as a whole. It said that it was therefore required to give weight to each of the different elements, and to consider their relationship to each other, when developing price controls.⁵ UR told us that it considered that the requirement to pursue its principal objective consistent with the objectives set out in Article 40 meant that the principal objective now incorporated Article 40, which related ‘a lot’ to consumer protection, and it said that it was mindful of the fact that under the transposition of European legislation into national law there was parity between its focus on consumers and the focus on the industry.

2.10 UR told us that it considered that particular weight should be given to the following matters:

⁵ UR [initial submission](#), paragraphs 2.12 & 2.14.

- (a) Sufficient revenues should be granted to allow the licence holder to maintain its existing network and continue with its growth plan, which furthered the objective of developing and maintaining the gas industry in Northern Ireland and to ensure that it could finance the activities which were the subject of obligations placed on it under the legislation (Article 14(2)(a) of the Energy Order).
 - (b) The allowances should be those that were efficient, economic and (Article 40(d) of the Gas Directive) cost-effective in all circumstances.
 - (c) It must have regard to 'the need to ensure a high level of protection for the interests of consumers' (Article 14(2)(a) of the Energy Order) and generally ensure that consumers benefited from an efficient market which helped to ensure consumer protection (Article 40(g) of the Gas Directive).
- 2.11 PNGL said that in its view the UR's PNGL12 determination did not give proper weight to its principal objective which was the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland. PNGL said that UR had elevated its duty to protect the interests of consumers of gas above all other duties to which it was subject. In giving a predominant focus to the consumer protection imperative, PNGL said that UR had failed to give the focus required by the Energy Order and the Gas Directive to other duties and objectives which were by law afforded equal importance.

Current structure of the natural gas industry in Northern Ireland⁶

- 2.12 Northern Ireland gas suppliers sell to consumers by purchasing their gas from gas producers or wholesalers at prices that are set with reference to a UK trading hub known as the National Balancing Point. The Northern Ireland gas industry is part of a single price zone for gas that extends to north Germany. Gas is traded within that zone between a series of hubs, and prices differ between these hubs generally only to reflect transport costs.
- 2.13 Gas is conveyed via transmission and distribution networks, to supply gas to consumers' premises where it is metered. Each of these three functions is licensed separately. The higher-pressure gas transmission pipes feed the lower-pressure gas distribution network pipes and run from Larne, near where the gas interconnector from Scotland comes into Northern Ireland, south to Newry (and from there on across the border to Dundalk) and north to Londonderry.
- 2.14 The gas distribution network in Northern Ireland is currently divided into two distinct areas: the greater Belfast area, served by PNGL; and the Ten Towns area, which encompasses the major towns outside Belfast along the transmission pipe, is served by firmus.
- 2.15 The Greater Belfast area was opened to competition for domestic customers for the supply of gas in 2007, and the Ten Towns area will be opened to competition from April 2015. In Greater Belfast, Airtricity⁷ and firmus compete for domestic customers. Commercial customers have additional options (see Table 2.1). firmus stated that it supplied natural gas in greater Belfast to over 22,000 business and domestic customers. The final customer has a contract with the gas supplier, and the supplier pays a conveyance charge to the distribution company for use of the network, with this charge recovered through the final customer's bill.

⁶ From UR website, www.uregni.gov.uk/gas/market_overview/.

⁷ Phoenix Supply Ltd was sold to SSE plc (Airtricity). The sale was completed on 22 June 2012.

2.16 The structure of the industry and the relevant licensed parties are detailed in Table 2.1.⁸

TABLE 2.1 Northern Ireland gas operators and licence holders

<i>Function</i>	<i>Operators and licence holders</i>
Interconnector	Premier Transmission Limited operates the Scotland to Northern Ireland pipeline.
Transmission networks	Belfast Gas Transmission Limited is licensed to convey gas from Ballylumford Powerstation to the Greater Belfast and Larne areas. BGE Northern Ireland is licensed to convey gas in the North–West pipeline and the South–North pipeline.
Gas distribution companies	Phoenix Natural Gas Limited operates the distribution network in the Greater Belfast and Larne areas. firmus is licensed for the conveyance of gas within the towns along the route of North–West and South–North pipelines. firmus is committed to the construction of distribution networks in the towns of: Ballymena, Ballymoney, Coleraine, Londonderry, Limavady, Antrim, Armagh, Banbridge, Craigavon and Newry.
Gas supply companies	Airtricity, Viridian Energy Supply Ltd (Energia), firmus, Power Gas Ventures and VAYU hold licences to supply gas within the Greater Belfast and Larne areas (where Airtricity does not hold exclusivity). firmus holds a licence to supply gas within the towns along the route of the North–West and South–North pipelines. British Gas Trading, Premier Power and NIE each hold a licence to supply gas within Ballylumford power station. Coolkeeragh (ESB) holds a licence to supply natural gas within Coolkeeragh power station. Bord Gais Eireann Energy Supply holds a licence to supply gas within both Northern Ireland power stations.

Source: UR website www.uregni.gov.uk/gas/licences/.

2.17 UR regulates the gas industry in Northern Ireland including licensing operators/suppliers and regulating prices for transmission and distribution. Airtricity has the great majority of customers in its area and its pricing is regulated by UR, whereas firmus' pricing (as a supplier in the Greater Belfast area)⁹ is not regulated.¹⁰ CCNI said that firmus was undercutting Airtricity in order to attract customers.¹¹ firmus stated that it currently guaranteed to beat Airtricity's tariffs by at least 10 per cent in the first year and 5 per cent in the second year.

2.18 The process of conversion, and the costs involved, are described in paragraphs 4.103 and 4.104. CCNI said that both PNGL in Belfast and firmus elsewhere in Northern Ireland provided cash incentives to encourage customers to switch to gas. The incentives offered by PNGL allowed under the price control include free connection to the network and different amounts of 'cash back' (or boiler scrappage allowances) for the installation of gas appliances, depending on the householders' age, personal circumstances or the type of heating to be replaced. This can amount in some cases to an incentive worth over £1,500.¹² In addition, grants may be available— see paragraphs 4.95 to 4.98. The Northern Ireland Housing Executive and other social landlords generally have a policy of converting to natural gas where possible,¹³ and PNGL told us that it sought to ensure that new-build housing in its area used natural gas as a fuel of choice.

⁸ Source: www.uregni.gov.uk/gas/licences/.

⁹ firmus is regulated as a supplier and distributor in the Ten Towns area.

¹⁰ CCNI, Customers Experience in Natural Gas in Northern Ireland, p6.

¹¹ *ibid*, p6.

¹² *ibid*, p10.

¹³ *ibid*, p10.

Background to the Northern Ireland gas industry

- 2.19 The towns gas network in Belfast was decommissioned in the late 1970s/early 1980s. Northern Ireland had no viable natural gas fields of its own, and efforts in the 1980s to connect Northern Ireland to natural gas supplies from elsewhere were not successful. Consequently, consumers in Northern Ireland generally relied on oil as a heating source.¹⁴
- 2.20 In 1992, British Gas plc (BG) purchased Ballylumford power station in Larne and agreed to convert it from oil to gas, which involved constructing a new pipeline from Scotland to Larne, thus making natural gas available in Northern Ireland for the first time.¹⁵ As part of the acquisition, BG also agreed to investigate the possibility of establishing a natural gas distribution utility in Belfast.
- 2.21 BG commenced negotiating the terms of a licence to introduce and operate a gas network. PNGL (then owned by BG) was first granted a combined licence in September 1996 by the Department of Economic Development (the predecessor to DETI), following which it began to develop a new network to transmit, distribute and supply natural gas in its Licensed Area, which then included Larne and the Belfast conurbation and was later extended. The 1996 licence's mandatory development plan specifically required PNGL to develop a sustainable network through which natural gas was available to no less than 81 per cent of all properties within the Licensed Area within a fixed rolling timescale.¹⁶
- 2.22 PNGL noted that this was a greenfield investment presenting challenges different from those faced by mature utilities:¹⁷
- (a) The network and market for natural gas would be developed from scratch.
 - (b) Even if successful, the investment would not be recouped for a number of years.
 - (c) The licence included a mandatory development plan and required distribution channels to be set up.
 - (d) The willingness of customers to make the investment to switch to natural gas was uncertain.
 - (e) This was a time of significant political instability in Northern Ireland, creating additional risks and challenges in the construction and operation of the network.
 - (f) Uncertainties at initial investment around future regulatory treatment given the absence of established regulatory precedent.¹⁸
- 2.23 PNGL was given a licence to convey gas (at transmission and distribution levels) and to supply gas in the areas of the licence. This was set up on the basis of a 20-year recovery period. PNGL told us that the licence and regulatory structure were tailored to the unusual circumstances of the investment, and had the following features:¹⁹

¹⁴ PNGL [statement of case](#), paragraphs 2.3–2.5.

¹⁵ PNGL [statement of case](#), paragraph 2.6.

¹⁶ PNGL [statement of case](#) paragraphs 2.7 & 2.8.

¹⁷ PMGL [statement of case](#) paragraph 1.13. In Appendix E we set out PNGL's arguments it submitted in relation to the risks it faced in 1996.

¹⁸ PNGL [Response to the Authority's Supplementary Submission](#) ('PNGL response'), p94, paragraph 3.11 (f).

¹⁹ PNGL [statement of case](#), paragraph 2.17.

- (a) Revenue profiling: revenue recovery was profiled over a 20-year period to reflect the fact that it would take time for volumes (with a new-build network) to grow to a sustainable level. The licence included formulae to capitalize negative cash flows to be recovered later in the 20-year period, through higher conveyance charges. However, under-recovered revenues (known as the Z-factor) were subject to a lower rate of interest to discourage unnecessary under-recovery by PNGL.²⁰
- (b) Twenty-year rate of return: a fixed 8.5 per cent real pre-tax return on cash flows over 20 years. PNGL said that this was to reflect the expected average level of risk the company would face over that time frame and to encourage investors, given the profile of revenue recovery and inherent commercial risks.
- (c) Price control reviews: these reviews would reset price caps based on revised cost and volume forecasts for the remainder of the 20-year period.
- (d) A mandatory development plan: the licence set output targets requiring PNGL to build the gas network within its Licensed Area to a defined timetable.
- (e) Strong incentives: the licence provided a strong financial incentive to ensure efficient opex and capex spend in that PNGL was allowed a 100 per cent retention of outperformance, while requiring PNGL to meet a mandatory development plan for investment. The efficiency gains that resulted were then reflected in the forward-looking cost forecasts at each price control review. PNGL said that customers therefore benefited from the application of this ratchet mechanism as it encouraged PNGL to achieve efficiencies, which were then reflected in lower prices at subsequent price controls.

2.24 UR said²¹ that the price control reviews set a price cap using a discounted cash flow calculation set out in the revenue recovery formulae in the original licence. The price caps were expected to allow PNGL to recover revenues whose cumulative present value would be equal to the cumulative present value of allowed expenditure incurred in the development and operation of the network. Under this methodology opex and capex were treated similarly, unlike the standard model of utility regulation. It was not necessary to ascribe a value to the PNGL asset base under this licence and there was no concept in the licence of a 'regulatory asset base' at this time.

Development of PNGL's business

- 2.25 BG began construction activities on a transmission network in May 1996, and on a distribution network in Belfast in July 1996. BG established PNGL in September of that year. Gas was delivered to the first customer in December 1996.
- 2.26 PNGL said that its construction strategy had always been based on meeting or bettering the Mandatory Development Plan in the licence and to maximize the customer base as quickly as possible to keep costs to individual customers down.
- 2.27 PNGL said that its initial approach was to move through its Licensed Area, from the north where the transmission pipeline arrived, towards the south, building all networks that would ever be required in each area at one time. This 'build it and they will

²⁰ PNGL [statement of case](#), paragraph 2.20. Under-recovered revenues arise because in the early years of the network roll-out, there would be a limited number of customers who could not be expected to cover the costs of building the network from scratch at that time, and prices were initially kept low so as to encourage customers to connect to gas. These revenues would be collected at a later date, and in the meantime PNGL earned only the nominal bank base rate on the under-recovery (with no retail prices index (RPI) adjustment), PNGL [statement of case](#), paragraph 5.28.

²¹ UR [initial submission](#), paragraph 2.20.

come' strategy was based on the fact that it was essential to have network in the ground before premises could switch to natural gas.²² It said that its initial capex was forecast on this basis. However, a change in approach was adopted in 1999. Instead of focusing on an area-by-area approach, PNGL began to accelerate the wider roll-out of the network, in order to meet customer demand and secure as large a customer base as possible. It said that maximizing the number of connections would bring benefits for all customers through lower network charges in future control periods. As a consequence of this strategy about 20 per cent of PNGL's network was constructed in 1999 alone²³ and some reinforcement projects were deferred.²⁴

- 2.28 PNGL said that it worked closely with the Northern Ireland Housing Executive (NIHE), the local public housing authority, to convince it to adopt natural gas for heating systems in its housing on their normal 15-year replacement cycle. It also said that it worked closely with specifiers, architects, developers and builders to ensure that natural gas became the fuel of choice for all new-build developments, and with industrial and commercial customers to ensure that they would either build premises that would use natural gas or convert their existing premises to natural gas, especially where there were large loads. Finally, in relation to owner-occupied areas, PNGL prioritized areas in terms of value for money based on construction costs and initial take-up rates by customers.²⁵
- 2.29 PNGL said that by the end of the first price control period (in 2001), approximately 45,000 more properties within its Licensed Area, corresponding to approximately 600 km more network, had gas available and approximately £20 million additional investment had been completed by PNGL and its shareholders compared with the development plan envisaged at the time of the 1996 licence.²⁶ The profile of customer connections, and the number of properties passed by PNGL's network roll-out, is shown in Figure 2.2. PNGL said that approximately 150,000 domestic and business customers were now connected to PNGL's network, and this continued to grow at around 8,000 new customers each year.²⁷
- 2.30 UR indicated that there had been substantial underperformance in respect of the volumes of gas distributed by PNGL between 1996 and 1998 relative to the initial forecasts (supplied by PNGL in 1997). It stated that actual volumes over the period were about 76 million therms lower than originally envisaged in PNGL's 1997 submission to the regulator. UR said that revenue and connections were also less than those submitted in 1997. UR said that this was because customers failed to convert to gas at the rate that had been anticipated. PNGL noted that under its regulatory framework between 1996 and 2006, the relevant measure of success was the number of properties passed by the network, rather than the number of connections relative to forecasts and all Licence obligations had been met. PNGL's regulatory volume forecasts were set by UR in 1999 to equal the volumes that were actually achieved up to 1998, see paragraph 5.32. UR said that even after revisions, connections still fell short of expectations. Shortfalls were also observed for the volume of gas.²⁸ PNGL said that it had experienced strong volume performance against expectations set out in UR's determinations over most of the period to 2006.²⁹ But we note that there was a shortfall in 2005/06.

²² PNGL [statement of case](#), Annex 3, paragraphs 12 & 13.

²³ PNGL [statement of case](#), Annex 3, paragraph 5.

²⁴ PNGL [statement of case](#), Annex 3, paragraph 6.

²⁵ PNGL [statement of case](#), Annex 3, paragraph 14.

²⁶ PNGL [statement of case](#), Annex 3, paragraph 19.

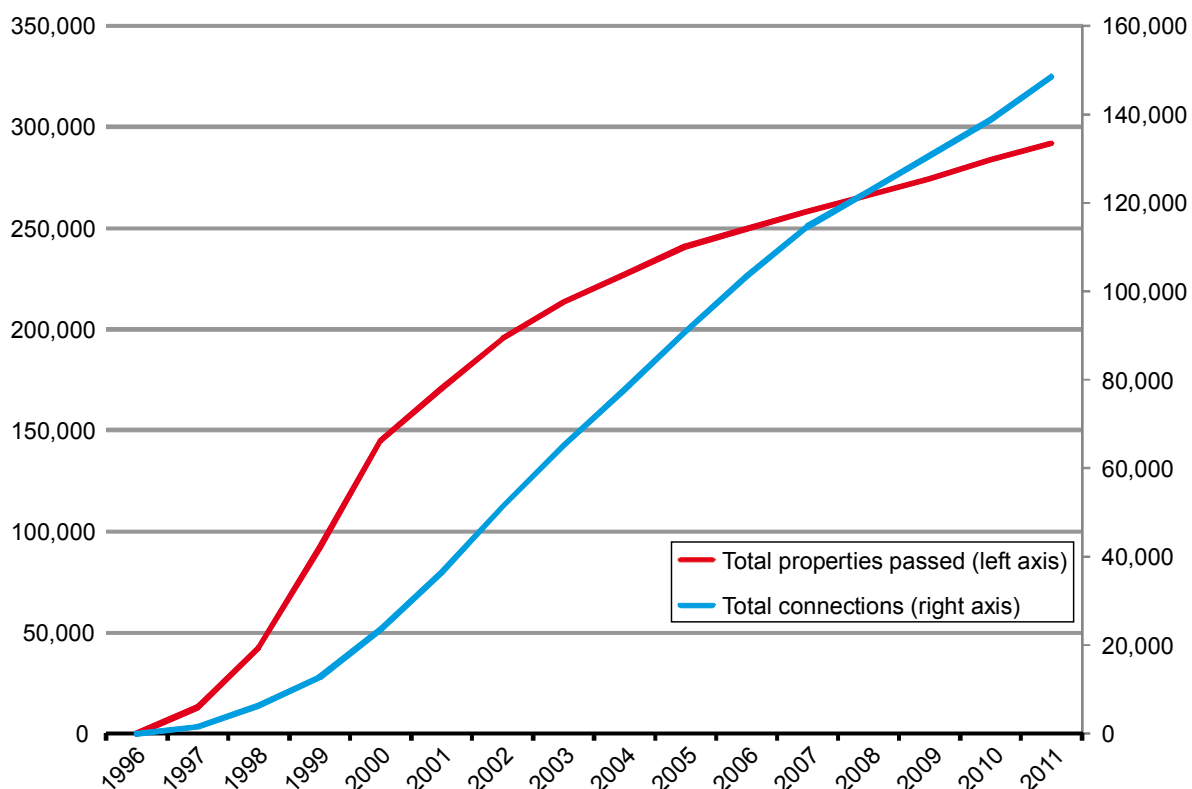
²⁷ PNGL [statement of case](#), paragraph 2.10.

²⁸ PNGL [response](#), paragraphs 2.22 & 2.23.

²⁹ PNGL [response](#), paragraphs 2.22 & 2.23.

FIGURE 2.2

Connections and properties passed



Source: PNGL Annual Development Plan and Business Model, from PNGL [statement of case](#), Figure 1.

- 2.31 PNGL said that it was not surprising that forecasts over 20 years might turn out to be inaccurate, and in accordance with standard regulatory practice, its licence provided for periodic reviews of cost and volume forecasts. It noted that its licence required PNGL to meet targets for passing properties in its Licensed Area which had been met.³⁰ PNGL said that under the terms of its 1999 licence it bore the risks of volume underperformance within each price control period, but that volume underperformance against target largely only occurred in the last two years to 2006. This net volume underperformance resulted in a reduction in the opening asset value (OAV, see paragraph 50) of around £3.5 million.³¹ It said that this volume underperformance arose from lower-than-expected average consumption per household because of more efficient boilers, better insulated housing, more customers on pay-as-you-go meters, and the closure of several large industrial customers.³²
- 2.32 In 2001, East Surrey Holdings plc (ESH) purchased a 24.5 per cent stake in PNGL. In December 2003 it bought the remaining stake in PNGL.
- 2.33 In April 2005 Kellen Acquisitions Limited, an acquisition vehicle for Terra Firma, announced an offer to acquire ESH. UR published a consultation on the proposed acquisition and noted that proposals different from the possible changes in the regulatory model then under consideration (see paragraph 2.48), might be considered. Terra Firma completed the acquisition of ESH in October 2005, following which new discussions began between the company and UR.

³⁰ PNGL [response](#), paragraphs 5.3 & 5.4.

³¹ PNGL [response](#), paragraph 5.6.

³² PNGL [response](#), paragraph 5.7.

- 2.34 In January 2007, PNGL's supply division was separated from its distribution business.
- 2.35 In January 2008 PNGL separated its distribution and transmission divisions, with sale of the transmission assets to Northern Ireland Energy Holdings Limited in March 2008.
- 2.36 In 2007 and 2008, there were also some licence modifications to allow extensions to PNGL's Licensed Area.
- 2.37 In May 2012, PNGL announced that it had reached an agreement to sell its gas supply businesses to SSE plc (Airtricity), subject to approval by the Irish Competition Authority.³³ The total cash consideration was £19.1 million excluding working capital related adjustments.³⁴ This sale was completed in June 2012.

Background to regulation

- 2.38 UR issued its first price control determination (PC01) in 1999, covering 1996 to 2001, three years into the period covered by the price control. Some months before the determination, PNGL, in the run up to the PC01 determination, decided to change its construction strategy compared with its initial plans, to accelerate its build programme within its Licensed Area so as to maximize the number of potential customer connections.³⁵
- 2.39 The second price determination (PC02) in April 2002 covered the period 2002 to 2006. An increase in conveyance charges was allowed, and PNGL implemented above-inflation price increases in October 2003 (reflecting inflation and increased gas wholesale prices, and to accelerate the return of under-recovered investment), and also looked for further increases in 2004. PNGL said that it received criticism from UR and CCNI at this time, as well as political pressure in relation to its pricing, even though its pricing strategy was within the limits permitted by the determination.
- 2.40 UR, in its PC02 price determination, indicated that there was a need to review the regulatory framework applying to PNGL³⁶ and there were discussions between UR and PNGL over an extended period which culminated in the 2007 determination.³⁷ PNGL and UR differ in their interpretation of the related events.
- 2.41 PNGL said that by 2002, both UR and PNGL had recognized that the cash flow model was not the best basis for the future development of the gas industry in Northern Ireland. It was common ground that a recovery period that reflected the expected economic lives of the network assets (ie stretching beyond the original 20-year recovery period) would help to maximize growth of the industry (through lower prices) and ensure a fairer sharing of investment cost recovery between current and future customers. It said that discussions began in 2002 between UR and PNGL to agree a sustainable longer-term cost recovery model.³⁸ It said that a longer-term financial framework for the industry was regarded as attractive by PNGL because this

³³ www.phoenixsupplyni.com/latest-news/item/99/phoenix-agrees-to-sell-gas-supply-businesses-to-sse-plc/. The businesses were PSL, and Phoenix Energy Limited, which supplies gas in the Republic's deregulated commercial supply market.

³⁴ www.sse.com/PressReleases2012/SSEAcquiresCustomersNI/.

³⁵ PNGL [statement of case](#), paragraph 2.21.

³⁶ See Appendix D, paragraph 151(j)(ii).

³⁷ We use the phrase '2007 determination' throughout this report to refer to the PC03 price determination and licence modifications together. While separate, and enacted at different times—see paragraphs 2.49 to 2.59—we have found it useful to have a term to refer to the effect of the package of measures together.

³⁸ PNGL [statement of case](#), paragraph 1.22.

would more formally reflect the considerable political and regulatory pressures of the time to keep prices to consumers low.³⁹

- 2.42 UR said that PNGL's revenue projections had been too optimistic and the market was not developing as strongly as envisaged. Weaker than expected demand meant that PNGL had to price well below the cap to support and encourage ongoing connections to the network. Therefore, PNGL significantly under-recovered compared with its allowed revenues,⁴⁰ and by the early 2000s, it was looking more and more likely that PNGL would be unable to recoup its investment within the 20-year time frame.
- 2.43 UR said that PNGL considered the possibility of raising its price substantially, which would have been risky and potentially harmful to the immature gas industry, and so this situation led to discussions and significant amendment to the PNGL licence.⁴¹ PNGL's actual conveyance charges (green line), and the price limits set by UR's determinations for the period 1996 to 2006 (blue line) are shown in Figure 2.3. UR also calculated in 2006 the price limit it would expect to apply to 2016 under the original licence. UR said that in order to have any prospect of recouping its investment, the actual charge would have had to treble from 2007 onwards, to recover the accumulated under-recoveries. UR said that PNGL's recovery of under-recovered revenues would have been limited under the original licence in that PNGL was only allowed to price to a level of no more than 10 per cent above the price limits set in UR's determination (the purple line), meaning that PNGL would have needed to write off at least £28 million under-recovered revenues (in addition to which PNGL would likely have lost additional revenues if it had raised its charges to the level allowed under the price cap).

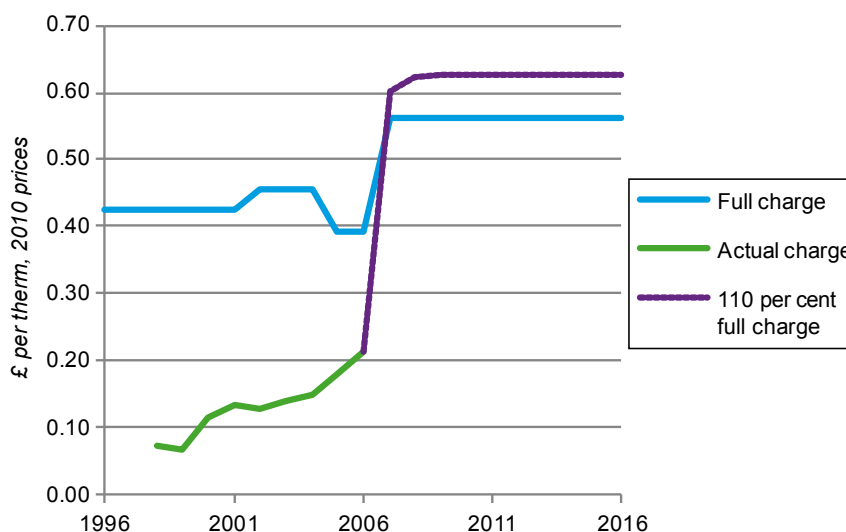
³⁹ PNGL [statement of case](#), paragraph 2.25.

⁴⁰ UR said that PNGL had under-recovered half of all revenues it had been allowed up to 2006.

⁴¹ UR [initial submission](#), paragraphs 2.21–2.23.

FIGURE 2.3

Actual conveyance charges and allowed charges 1996 to 2006, and UR's forecasts (as at 2006)



Source: UR, [Supplementary submission to the Competition Commission following PNGL's Statement of Case](#) ('UR supplementary submission'), Diagram 3.

- 2.44 PNGL disagreed with the analysis presented by UR as shown in Figure 2.3. PNGL noted that the price cap presented by UR in Figure 2.3 was flat from 2006 onwards whereas it said Condition 2.3.9 of the 1996 licence stated that the amount of Z⁴² that could be recovered in any given year was limited to 10 per cent of the previous year's allowed revenue implying increasing prices over time.
- 2.45 PNGL disagreed with UR's assertion that PNGL's business plan had failed by 2006. It said that this was because PNGL could have recovered its costs fully by operating to the terms of the 1996 licence: it could have priced to the cap for the remainder of the initial recovery period, and any outstanding under-recovery in 2016 would have been dealt with as residual value in accordance with arrangements that would have been agreed with UR under the terms of its licence. PNGL added that Terra Firma invested in PNGL on the basis of the 1996 licence and would have been prepared to continue with the 1996 licence.⁴³
- 2.46 PNGL said that it had built up sufficient customer connections that it could have coped with a need for a substantial pricing increase had the 1996 licence been retained, and that past price fluctuations had shown that customers would still continue to connect to the gas network even if prices did increase.⁴⁴
- 2.47 PNGL said that between 2002 and 2004, discussions on a new framework led to an agreement to move to a recovery mechanism that had an explicit regulatory asset base, with PNGL's licence moving to a 40-year cost recovery period and PNGL retaining a rate of return of 8.5 per cent. PNGL would also divest its transmission assets. However, these discussions did not then lead to a public consultation or

⁴² Z is the parameter in the formula for under-recoveries of revenues in any year, see paragraph 2.23(a).

⁴³ PNGL [statement of case](#), p8. There appears to be a difference in perception between PNGL and UR as to whether the 1996 licence permitted full recovery of under-recoveries in the period post-2016. While PNGL said that this was possible, UR said that the 1996 licence stated at Condition 2.3.14 that the allowances post-2016 would be based on allowances to cover opex, renewals, expansion and reinforcement of the system, but there was no reference to any outstanding under-recoveries.

⁴⁴ PNGL [response](#), paragraph 5.8.

adoption of the proposals in PNGL's licence, mainly as a result of Terra Firma's intention to acquire PNGL's business see paragraph 2.33.⁴⁵

- 2.48 In 2006, further discussions were held between PNGL and UR, leading to a proposed package of modifications in November 2006. This was followed by a public consultation (the consultation paper on PNGL restructuring and proposed price control licence modifications was issued on 6 April, 2007), after which, on 20 August 2007, UR published a decision to modify the price control conditions in PNGL's licence (the 2007 licence modification). On 30 November 2007, UR published the PC03 (2007) determination covering the period of 2007 to 2011.
- 2.49 PNGL summarized the key components of the 2007 determination as:⁴⁶
- (a) an extension of the cost recovery period in the licence from 20 years to 50 years;
 - (b) the introduction of a price control mechanism based explicitly on a regulated asset value and the determination of a figure as an OAV (we also refer to this as the 2006 TRV) which was incorporated into the licence (£312.8 million);
 - (c) the establishment of the depreciation profile, which determined the period over which PNGL could recover the TRV and any new capex, and the introduction of the profile adjustment (the mechanism to profile the recovery of revenue in line with the expected growth in volumes over time);
 - (d) the mutualization and sale of PNGL's transmission business; and
 - (e) a reduction in the rate of return for the distribution business from 8.5 per cent to 7.5 per cent through to the end of 2016 (at which point it would be reviewed in line with best regulatory practice at the time).
- 2.50 The OAV of £312.8 million (2006 prices) set out in paragraph 2.49(b) comprised a number of elements: 54 per cent represented PNGL's past investment in developing the network that had not yet been paid for by customers; 21 per cent represented the capitalized value of accumulated under-recoveries of revenues (due to PNGL pricing below the price cap); and 25 per cent represented the capitalized value of unspent allowances (ie opex, capex) and WCA outperformance, volume underperformance, and deferred capex.⁴⁷
- 2.51 The value of accumulated under-recoveries of revenue included in the OAV was £66 million (in 2006 prices).⁴⁸ UR said that it did not require PNGL to write off the estimated £28 million that PNGL could not have recovered under the 1996 licence—see paragraph 2.42.⁴⁹ It was determined in the 2007 revisions that the unrecovered revenue that went into the OAV should be capitalized using the lower rate of return set out in the 1996 licence (see paragraph 2.23). In addition a 2 per cent real rate of return was used for these under-recoveries for a further ten years (ie for the period of 2007 to 2016).⁵⁰
- 2.52 Outperformance (discussed in detail in Section 5) represents the difference between actual costs and the allowed targets for operating and capital expenditure under the applicable price determinations. Between 1996 and 2006, PNGL overall spent

⁴⁵ PNGL [statement of case](#), paragraphs 2.29–2.33.

⁴⁶ PNGL [statement of case](#), paragraph 2.41.

⁴⁷ UR [initial submission](#), paragraph 2.27.

⁴⁸ PNGL [statement of case](#), Annex 10 (tab 'Summary').

⁴⁹ UR [supplementary submission](#), paragraph 2.27, footnote 21.

⁵⁰ PNGL [statement of case](#), paragraph 5.29.

£37.2 million (2006 prices) less than the allowances set in the price controls. As noted in paragraph 2.23(e), PNGL was entitled to retain the benefits of such out-performance under the 1996 licence. Because of the smoothing of prices and the deferral of revenues, PNGL had not received any benefit for outperformance between 1996 and 2006 (nor had it been penalized for underperformance on volumes). While UR had proposed that some sharing of historic outperformance between PNGL and the customer should be reflected in the calculation of the OAV, in the end it was determined that the full value was included in the OAV at that time (including the returns which had also been earned up to 2006 on this underspend).⁵¹

2.53 Table 2.2 sets out the components of the outperformance included in the 2007 OAV.

TABLE 2.2 Components of the outperformance adjustment in the OAV

	£'000
	<i>Commercial</i>
Opex outperformance	24,707
Capex outperformance	51,584
Volume outperformance	-3,594
WCA	5,000
Grants	0
Total outperformance	77,697

Source: PNGL.

2.54 The value of capex outperformance in Table 2.2 includes deferred capex,⁵² ie capital expenditure that had been allowed but where the particular projects were delayed (giving rise to financial benefit) or had not yet been undertaken. UR indicated in its determination that a subset of deferred capex (the 1999/2000 capex deferrals) would be subject to further review, see Section 6.⁵³ However, the outperformance associated with WCAs was reduced and outperformance against grants was removed. UR said that the 1996 licence did not intend to allow outperformance on WCA (see paragraph 5.183) and that it would not be appropriate for PNGL to keep public funds (ie grants) as profits.

2.55 As part of the 2007 revisions, PSL (the Phoenix supply business) was required to write off losses on some legacy supply contracts.⁵⁴

2.56 As such the value of outperformance and unrecovered revenues was rolled up into the OAV. That value was to be recovered through depreciation of the asset base (essentially the TRV) over the subsequent 40 years with a real rate of return of 7.5 per cent up to 2016, and, thereafter, at a rate to be determined by UR.

2.57 PNGL summarized⁵⁵ the key features of the PC03 price control as:

- (a) a significant reduction in operating costs to reflect operating efficiencies that PNGL had achieved;
- (b) a rolling five-year incentive allowing PNGL to retain the benefit of future capex outperformance, or suffer the consequences of capex overspends for a rolling five-year period;

⁵¹ PNGL [statement of case](#), paragraphs 2.44 & 2.45.

⁵² PNGL [statement of case](#), paragraph 2.48.

⁵³ PNGL [statement of case](#), paragraph 5.13.

⁵⁴ PNGL [statement of case](#), paragraph 2.46.

⁵⁵ PNGL [statement of case](#), paragraph 2.56.

(c) a change to PNGL's revenue driver to a part-fixed, part-connection revenue driver, rather than one based on the volume of units of gas (UR noted that the connection incentive mechanism was relatively minor in magnitude and so it said that for practical purposes PNGL could be considered subject to a revenue cap); and

(d) clarification of the treatment of deferred capex.

- 2.58 PNGL said that UR's PC03 determination also confirmed the value of deferred capex for the 2006 TRV in line with the 2006 'agreement' on the package of modifications.⁵⁶ PNGL said that PC03 also established a methodological precedent for netting future capex allowances off against that figure.⁵⁷
- 2.59 A licence modification to give effect to the terms of the PC03 determination was made in June 2009. In February 2010, there was a licence modification to remove the cap on the number of prepayment metres for which PNGL could recover costs. In July 2010, UR issued a PC03 supplemental determination (retrospective adjustments and rolling capex incentive) which specified the details of how a number of cost items would be retrospectively adjusted at the time of the next price control to correct for deviations between forecast and out-turn events during the 2003 price control period.⁵⁸
- 2.60 PNGL said that with the PC03 settlement agreed, it undertook further investment and achieved ongoing operational efficiencies within what it understood to be a stable and predictable regulatory environment.⁵⁹

PNGL12

- 2.61 In May 2010 UR decided to align the price control periods of Northern Ireland's two gas distribution networks, PNGL and firmus energy. Consequently the fourth price control for PNGL covered just two years—2012 and 2013. Following the submission of the PNGL business plan in late 2010 and consideration by UR, and following discussions with PNGL, UR consulted on its proposals for the 2012/13 price control in August 2011, over an eight-week period.⁶⁰
- 2.62 UR told us that that it had carefully examined PNGL's business plan, and had proposed an allowance for opex and capex in each year of the control period, using a standard RPI-X framework to develop the price control in order to incentivize PNGL to control its costs.⁶¹ PNGL's submission on capex was reviewed with the help of engineering consultants PB Rune.⁶² An ongoing efficiency factor of 1 per cent was applied.⁶³ UR did not propose any changes to PNGL's allowed rate of return.⁶⁴
- 2.63 UR said that over the course of PC03 PNGL added £98.5 million (in 2010 prices) net for capitalized expenditure on to the TRV (as PNGL had continued to develop and build out its network, and as PNGL continued to defer recovery of some of its entitled

⁵⁶ PNGL [statement of case](#), paragraph 1.35. See also paragraph 2.48.

⁵⁷ PNGL [statement of case](#), paragraph 1.35.

⁵⁸ See [UR, Phoenix Natural Gas Limited Price Control Review 2012-2013: Final Decisions, January 2012](#) ('UR PNGL12 determination'), paragraphs 8.2 & 8.3.

⁵⁹ PNGL [statement of case](#), paragraph 2.57.

⁶⁰ UR [initial submission](#), paragraph 3.7.

⁶¹ UR [initial submission](#), paragraph 3.8.

⁶² UR [initial submission](#), paragraph 3.12.

⁶³ UR [initial submission](#), paragraph 3.13.

⁶⁴ UR [initial submission](#), paragraph 3.14.

revenues, which was secured for PNGL by way of an addition to its asset base via the profile adjustment). This amount was undisputed between UR and PNGL.

- 2.64 The main change proposed by UR in the 2012 charge control compared with the 2007 charge control involved a reduction of the TRV of around £75 million (the 2012 TRV adjustment). This consisted of an adjustment for outperformance and deferred capex (and in particular the 1999/2000 capex deferrals) which was included in the 2007 opening TRV and which had accrued in the period 1996 to 2006 (see paragraphs 2.52 to 2.56).
- 2.65 UR said that the 2012 TRV adjustments were in relation to monies that were not spent. This was not the same as capital investments that were made and needed to be financed.⁶⁵ PNGL observed that by its very nature, outperformance was money that had not been spent, since it had been saved due to innovations leading to more efficiency and lower costs.
- 2.66 UR said that deferred capex referred to allowances for projects PNGL had yet to complete, or which were completed later than originally anticipated. As a result PNGL's asset base had increased by more than it would otherwise have if allowances were (or are) included only at the time of actual spend. It said it formed the opinion that the company should not retain the benefit of a failure to deliver assets or the delivery of assets later than originally scheduled.⁶⁶ PNGL said that its 1996 licence did not draw a distinction between deferred capex and any other outperformance.
- 2.67 UR said that it was standard regulatory practice that the benefits from outperformance were shared between companies and consumers.⁶⁷ It proposed allowing PNGL to retain the historic outperformance sum in its TRV until the end of 2011, by which time it said that PNGL had enjoyed five years of reward (by way of depreciation and return) from its inclusion, amounting to around £35 million, but then removing the residual value of outperformance remaining in the TRV at the end of 2011. PNGL said that such an approach had been considered at the time of the 2006 'agreement' on the package of modifications, but was not adopted as part of the negotiated package of measures. It was not reflected in the value for TRV embedded in PNGL's licence and nor was it reflected in UR's financial models.⁶⁸
- 2.68 UR said that, even after the 2012 TRV adjustment, the remaining TRV included significant elements of historical under-recoveries and some historical outperformance. These would continue to be part of the TRV and did not require any future adjustment.⁶⁹ It considered that the adjustment represented the closing off of a range of historic issues relating to PNGL and once implemented, by way of a licence modification, should provide a significant element of certainty to investors.
- 2.69 UR said that it was not in the public interest for PNGL to earn 40 years of return on unspent allowances because this would be contrary to the standard regulatory approach taken by any regulator in Great Britain. It was also contrary to any economic theory which underpinned incentive regulation and in a competitive market it would not be possible to retain the benefit of efficiencies for 40 years. PNGL noted

⁶⁵ UR [supplementary submission](#), paragraph 1.21.

⁶⁶ UR [initial submission](#), paragraph 3.16.

⁶⁷ UR [initial submission](#), paragraph 3.19.

⁶⁸ PNGL [statement of case](#), Section 4.

⁶⁹ UR [PNGL12 determination](#), paragraph 7.69.

that there was a distinction between how much outperformance the company kept, and how many years it took to recover this as revenue.⁷⁰

- 2.70 UR said that PNGL had accepted in 2007 and still accepted that the five-year rolling incentive (for opex and capex outperformance) was an appropriate incentive.⁷¹ UR said that without the 2012 TRV adjustment PNGL would earn disproportionately high revenues when compared with the investments it actually made and the risks it took.⁷² UR said that Northern Ireland had long had the highest rate of fuel poverty in the UK (at 44 per cent) and it was therefore not in the public interest for PNGL to earn unjustifiably high returns.⁷³ With the TRV adjustment proposed by UR it had estimated that prices would fall by £10 a year compared with 2011; without the TRV adjustment it estimated that prices would rise by £6 a year.⁷⁴ UR said that any regulatory uncertainty created by the 2012 TRV adjustment needed to be seen in the context of the £80.2 million benefit to consumers as a result of the adjustment.⁷⁵ UR said that the issue was whether gas consumers benefited (in the short and long term) more from the TRV adjustment or from paying for costs (including a rate of return on those costs, until 2046) that were never incurred in the expectation that this may deliver an equivalent or greater benefit through future impacts on the cost of capital.⁷⁶
- 2.71 UR noted that while PNGL accepted many elements of UR's proposals (subject to some minor debate and revision of details), it objected strongly during the consultation period to the proposal to adjust the TRV for deferred capex and outperformance. UR said PNGL argued that this was unexpected, retrospective in nature and would unwind a 'deal' that was struck between it and UR in 2006/07.
- 2.72 PNGL said that it was not until the publication of UR's consultation on PNGL12 in August 2011 that UR indicated that it planned to make the 2012 TRV adjustment. PNGL said that this amount was around 20 per cent of the value of PNGL's TRV.⁷⁷ PNGL said that this was despite it having had previous related discussions with UR on the roll forward of the TRV for the PC03 actual out-turn.⁷⁸
- 2.73 PNGL contended that implementation of the proposal would be likely to erode investor confidence and so increase the cost of capital for both PNGL and other utilities in Northern Ireland, to the detriment of consumers. It claimed that this would therefore be inconsistent with UR's statutory duties under the Energy Order and with regulatory best practice more generally.⁷⁹
- 2.74 UR reviewed PNGL's arguments but did not accept them given its views of its statutory duties, and it was not persuaded that the determination would hinder the development of the gas industry in Northern Ireland.⁸⁰ It said that this was because:
- the specific proposals to which PNGL objected related not to past investment but to the treatment of monies that the company did not spend;

⁷⁰ PNGL [response](#), Annex 1.

⁷¹ UR [supplementary submission](#), paragraphs 1.7 & 2.2.

⁷² UR [supplementary submission](#), paragraphs 1.14, 1.15, 2.5 & 2.16.

⁷³ UR [supplementary submission](#), paragraphs 1.17 & 2.17.

⁷⁴ Note that the PNGL12 price determination also includes other significant changes apart from the TRV adjustment which also affect how prices change compared with 2011, see paragraph 9.93.

⁷⁵ UR [supplementary submission](#), paragraphs 1.9 & 1.13. See also the footnote to paragraph 4.113.

⁷⁶ UR [supplementary submission](#), paragraph 2.14.

⁷⁷ PNGL [statement of case](#), paragraph 1.36.

⁷⁸ PNGL [statement of case](#), paragraph 1.36.

⁷⁹ UR [initial submission](#), paragraph 1.9.

⁸⁰ UR [initial submission](#), paragraph 1.14.

- the proposals were careful to ensure that customers paid for all efficiently incurred capitalized expenditure that PNGL had actually put into the gas network in Northern Ireland since 1996 including the licence-allowed cost of capital;
 - the proposals set out a commitment to ensure that customers would pay for all future capitalized expenditure that PNGL efficiently incurred;
 - in so far as PNGL had to finance investment ahead of payment by customers, it was to be allowed a real pre-tax return of 7.5 per cent a year until 2016—the highest cost of capital allowance that was on offer to a comparable regulated business in the UK; and
 - the proposals did not impede PNGL’s ability to finance its business.⁸¹
- 2.75 PNGL said that the financeability assessment that UR carried out was not fit for purpose and ignored the licence framework.⁸²
- 2.76 PNGL said that the 2006 TRV formed part of the 2006 ‘agreement’ on the package of modifications. It said that between 2002 and 2006, all aspects of the 2006 ‘agreement’ were discussed and debated at length, and were publicly consulted upon.⁸³ It said that this effectively ratified an agreed approach to sharing value between PNGL and its customers, present and future.⁸⁴ It said that the 2006 ‘agreement’ was recognized publicly by both PNGL and UR as benefiting both customers and PNGL, distributing benefits fairly between them.⁸⁵ It said that the 2006 ‘agreement’ (and in particular the 2006 TRV) was subsequently incorporated into PNGL’s licence⁸⁶ and was intended to ‘draw a line under the past’.⁸⁷ It said that there was no defect in the 2006 ‘agreement’ and no new information had arisen since it was concluded that would suggest otherwise.
- 2.77 PNGL said that the test referred to by UR in paragraph 2.69 and 2.70 (ie whether a cut in customer prices was offset by the impacts of the cost of capital) misapplied the requirements of its licence, the Gas Directive and Energy Order and was mis-conceived).
- 2.78 PNGL said that the 7.5 per cent rate of return for 2007 to 2016 was set as part of the package of measures implemented under the 2006 agreement, and continued to reflect the long-term nature of the original greenfield investment, and the expected average risks over the 20-year period to 2016. PNGL provided a calculation for the Internal Rate of Return of its investments to date, which, it claimed, showed that without the 2012 TRV adjustment the IRR would be 7.93 per cent (real pre-tax). It said that this was below the weighted average of the ex ante cost of capital (also real pre-tax) PNGL had been allowed since 1996 (which it said was around 8.2 per cent).⁸⁸ It said that the analysis shows that PNGL had not earned disproportionate or excess returns.⁸⁹ It said there were therefore no grounds for UR to reopen the ‘agreement’.⁹⁰

⁸¹ UR [initial submission](#), paragraph 1.17.

⁸² PNGL [response](#), Section 8.

⁸³ PNGL [statement of case](#), paragraph 1.4.

⁸⁴ PNGL [statement of case](#), paragraph 1.24.

⁸⁵ PNGL [statement of case](#), paragraph 1.4.

⁸⁶ PNGL [statement of case](#), paragraphs 1.4 & 1.5.

⁸⁷ PNGL [statement of case](#), Section 4 and [response](#), Section 7.

⁸⁸ PNGL [statement of case](#), paragraph 5.84.

⁸⁹ PNGL [statement of case](#), paragraphs 5.82 & 5.86.

⁹⁰ PNGL [statement of case](#), paragraph 1.33.

- 2.79 PNGL said that the 2012 TRV adjustment substantially and retrospectively reduced the 2006 TRV value that was embedded within PNGL's licence.⁹¹ It said that this was a reopening of the 2006 'agreement', which caused considerable regulatory uncertainty, severely undermined investor confidence and changed the basis on which PNGL had taken its investment decisions since 2006. This was to the detriment of both PNGL and its customers, and to the task set for PNGL of introducing a natural gas infrastructure to Northern Ireland.⁹²
- 2.80 PNGL said that these decisions would have an impact not just on PNGL and its customers, but, if upheld, on other utilities in Northern Ireland and on regulators and regulated utility businesses more widely in Great Britain.⁹³ It said that preventing bad regulatory practice and establishing a stable regulatory environment was in the public interest.⁹⁴ PNGL said that UR's proposals (if upheld) were expected to lead to higher costs to consumers in the longer term given increases in the cost of investment, lower levels of efficiency savings and potential delays to expansion of the gas network to new areas.
- 2.81 PNGL said that it did not challenge the treatment of outperformance earned in the most recent price control period (ie from 1 January 2007 to 31 December 2011) since the sharing mechanism applied to that outperformance was agreed and understood ex ante. PNGL was disputing only the reopening of the treatment of outperformance earned in previous price control periods, between 6 and 16 years ago.⁹⁵
- 2.82 In February 2012 PNGL issued a review Disapplication Notice and rejected the proposed licence modifications, and in March UR made its reference to the CC.

⁹¹ PNGL [statement of case](#), paragraphs 1.4 & 1.5.

⁹² PNGL [statement of case](#), paragraph 1.8.

⁹³ PNGL [statement of case](#), paragraph 1.7.

⁹⁴ PNGL [statement of case](#), heading to paragraph 1.50.

⁹⁵ PNGL [statement of case](#), paragraph 1.34 and Annex 5, paragraph 16.

3. The reference

- 3.1 UR has made this reference in accordance with Article 15(1) of the Gas Order and the procedures set out in Condition 2.3.13(d) of PNGL's Licence, as PNGL has not consented to licence modifications proposed by UR, following a periodic review by UR of the charges PNGL may make for the conveyance of gas to premises in the years 2012 and 2013.

Legal framework

- 3.2 The regulatory regime applying to gas distribution in Northern Ireland is in many respects similar to that applying in Great Britain,¹ but there are also material differences. Energy policy is now the responsibility of DETI, and licences for the supply, conveyance and storage of natural gas are now granted by the national regulatory authority² (now UR), under Article 8 of the Gas Order.³

The Order

- 3.3 Conveyance (distribution) of natural gas in Northern Ireland is regulated principally by the Gas Order and by the conditions of licences granted under the Gas Order. The objectives of gas regulation and the duties of UR are set out in the Energy Order⁴ as amended, in particular, by the Gas and Electricity (Internal Markets) Regulations (Northern Ireland) 2011⁵ (which transposed certain requirements of the EU Third Energy package⁶ into law in Northern Ireland).

The licence

- 3.4 PNGL has a licence dated 5 September 1996, granted under Article 8(1) of the Gas Order, to 'convey gas from one place to another in an area authorised by the licence'⁷ (ie Greater Belfast and Larne) and the right is exclusive until 2016. In 2007, the licence was modified so that 'conveyance' (which formerly combined both transmission and distribution) was limited to distribution, and PNGL's transmission business was sold. As noted in paragraph 2.37, in 2012, Phoenix sold its supply company, PSL, so PNGL is now responsible for the pipeline network in its area, and for connecting premises in its area to the gas network, but no longer supplies gas directly to end-users.
- 3.5 Part 1 of PNGL's licence contains general conditions applicable to licence holders as well as conditions specific to PNGL. Condition 1.1.6, read with Schedule 1 to the licence, specifies the area in which PNGL has exclusive authority to carry on the conveyance of gas. Condition 1.10 provides that the conditions of the licence are subject to modification, in accordance with their own terms, or with specified articles of the Gas Order or relevant articles of the Energy Order. Other conditions in Part 1

¹ ie under the [Pipe-lines Act 1962](#) and the [Gas Act 1986](#) as amended, which provide the framework for the natural gas industry in Great Britain.

² Article 39.3 of the Gas Directive allows member states, by way of derogation, to designate a separate national regulatory authority for small systems in a geographically separate region, such as Northern Ireland. The power of DETI to award such licences was transferred to the regulatory authority by the Energy Order.

³ SI 1996 No 275 (NI 2) made under powers given by the Northern Ireland Act 1974.

⁴ SI 2003 No 419 (NI 6).

⁵ SR 2011 No 155.

⁶ In particular, as regards gas, Directive 2009/73/EC of the European Parliament and of the Council concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC OJ (2009) L 211/94.

⁷ Originally the licence was a combined licence covering both conveyance (under Article 8(1)(a)) and supply (under Article 8(1)(c)) of natural gas, but this combined licence was divided into separate licences for conveyance and for supply of natural gas on 19 December 2006.

deal with financial matters, including the requirement, in Condition 1.22.4, for PNGL to take all appropriate steps to ensure that PNGL obtains and thereafter maintains an investment grade credit rating.

- 3.6 Part 2 of the licence contains conditions which are specific to the conveyance of gas by PNGL. In particular, Condition 2.3 concerns charges and other terms for the provision of conveyance services. Condition 2.3.8 sets out a charging methodology for the conveyance of gas, and Conditions 2.3.10 to 2.3.13 set out the process by which the core terms of the price control will be established by UR from time to time.

Price control reviews

- 3.7 Condition 2.3.11 provides that a review of the core terms of the price control will take place at scheduled intervals. Under this procedure, after making its determination of the core terms, UR must serve a Determination Notice on PNGL in respect of the core terms of the price control it proposes to apply in the next pricing period.⁸ In each formula year PNGL can set charges to customers on a per therm basis (as agreed with the regulator), but PNGL's actual revenues will depend on the volumes of gas used. PNGL will also receive additional penalties or payments under connection incentive arrangements. Any deviations from assumptions made in the determination are recovered as part of an adjustment to revenues in the following year.
- 3.8 Following a price review, UR issues a Determination Notice setting out the new values that will apply in PNGL's licence in accordance with Licence Condition 2.3.13(e): the consent of PNGL is not required. However, PNGL has a right to serve a Review Disapplication Notice⁹ on UR within 28 days of receiving the relevant Determination Notice. If PNGL serves a Disapplication Notice, the proposed determination has no effect and the core pricing terms established by the preceding Review continue to apply.
- 3.9 If UR wishes to challenge the rejection of its determination by PNGL, it must make a reference¹⁰ to the CC within 56 days from the date of the Disapplication Notice. The decision of the CC made on the reference is binding both on PNGL and on UR.¹¹
- 3.10 The procedure set out in Licence Condition 2.3.13 reflects the general terms of Article 14(1) of the Gas Order, which gives UR power to modify the conditions of a particular licence, but provides that UR must not do so unless the licence holder consents.¹²

The reference

- 3.11 Article 15 of the Gas Order allows UR to require the CC to investigate and report on two questions:

⁸ Condition 2.3.13(c) of the licence.

⁹ In accordance with Licence Condition 2.3.13(d).

¹⁰ In accordance with Article 15 of the Gas Order and Condition 2.3.13(d) of the licence.

¹¹ Re *Northern Ireland Electricity plc's Application for Judicial Review* [1998] NI 300.

¹² Article 14(6)(a) of the Gas Order.

- (a) whether any matters which relate to the carrying on of activities regulated by the licence and are specified in the reference operate, or may be expected to operate, against the public interest; and
- (b) if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the relevant conditions of the licence.
- 3.12 The specific matters which UR has required the CC to investigate are ‘the Price Control Conditions’. This term is defined in Recital B to the reference and refers to Licence Conditions 2.3.8 to 2.3.26 which deal with conveyance charges and other terms for the conveyance of gas.
- 3.13 UR may vary a reference, and may specify in the reference, for the purpose of assisting the CC, any effects adverse to the public interest which, in the opinion of UR, the matters specified in the reference have, or may be expected to have; and any modifications of the relevant conditions by which, in the opinion of UR, those effects could be remedied or prevented.¹³
- 3.14 Accordingly, the UR has specified that the effects adverse to the public interest, which the Price Conditions have or may be expected to have, include the payment by gas consumers in Northern Ireland of higher prices for the conveyance of gas by PNGL than are necessary or appropriate, to the detriment of those consumers and of the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland.
- 3.15 UR has a duty, under Article 15(7) of the Gas Order, for the purpose of assisting the CC in carrying out its investigation, to give the CC any information in its possession which relates to matters falling within the scope of the investigation and is requested by the CC or is information which, in the opinion of UR, it would be appropriate for that purpose to give to the CC without any such request. UR must give the CC any other assistance which the CC may require and which it is in the power of UR to give. The CC is required to take account of any such information given by UR for the purposes of the reference.¹⁴ Article 15(8) of the Gas Order provides that, in determining whether any particular matter operates, or may be expected to operate, against the public interest, the CC must have regard to the matters as regards which duties are imposed on UR by Article 14 of the Energy Order.

The statutory duties

- 3.16 In making our determination, we are required to have regard to the duties of the UR as set out in the Energy Order.¹⁵ The requirement to have regard to the duties of the UR does not, of course, mean that we are required to follow the same approach that the UR has adopted or adopt the same methodologies.
- 3.17 The Energy Order provides that UR must carry out its functions in relation to gas in the manner which it considers is best calculated to further the principal objective, having regard to a number of specified duties. The principal objective is to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland, and to do so in a way which is consistent with the fulfilment by the Authority of the objectives set out in paragraphs (a) to (h) of Article 40 of

¹³ Article 15(4) of the Gas Order.

¹⁴ Article 15(7) of the Gas Order.

¹⁵ Article 15(8) of the Gas Order.

the Gas Directive (General objectives of the regulatory authority). Article 14 of the Energy Order and Article 40 of the Gas Directive are set out in Appendix B.

3.18 In addition, when carrying out its functions, UR must have regard to a number of other considerations. These include:

- (a) the need to ensure a high level of protection of the interests of consumers of gas; and
- (b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Gas Order or the Energy Order.¹⁶

In carrying out that duty, UR must also have regard to the need to protect the interests of:

- (i) individuals who are disabled or chronically sick;
- (ii) individuals of a pensionable age; and
- (iii) individuals with low incomes.¹⁷

But that is not to be taken as implying that regard may not be had to the interests of other descriptions of consumer. UR may also, when carrying out any gas functions, have regard to the interests of consumers in relation to electricity and in relation to water or sewerage services.¹⁸

3.19 In paragraphs 2.9 to 2.11, we have set out some of the explanations provided by UR on how it has sought to interpret and apply its duties. However, we consider that UR's interpretation does not prevent the CC from forming its own view on how these duties are to be taken into account in making its determination.

3.20 In addition to taking into account the statutory duties set out in the Energy Order, we have also had due regard to established general principles of administrative law and principles of regulatory best practice (ie that regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed).

The CC's approach

3.21 The reference requires the CC to investigate and report on whether the Price Control Conditions in PNGL's Licence operate or may be expected to operate against the public interest and, if so, whether the adverse effects could be remedied or prevented by making a licence modification.

3.22 The consequence of PNGL having rejected UR's Determination Notice is that the revised price control proposed by UR has no effect. We are therefore required to consider whether the current Price Control Conditions will operate, or may be expected to operate, against the public interest in the years 2012 and 2013. It is only if that question is answered in the affirmative that the CC is required to proceed to consider whether the effects adverse to the public interest could be remedied or

¹⁶ Article 14(2)(a) and (b) of the Energy Order.

¹⁷ Article 14(3) of the Energy Order.

¹⁸ Article 14(4) of the Energy Order.

prevented by licence modifications. The starting point for the CC's work is therefore the current licence conditions.

- 3.23 Of course, in considering the reference, the evidence of UR's proposals and submissions and of PNGL's submissions, and consideration of the differences between UR's views and PNGL's views, have been useful in informing our conclusions. It is inevitable that to some degree the matters that are in issue between UR and PNGL will be those that are highly relevant to a determination as to whether the current licence conditions operate, or may be expected to operate, against the public interest. However, we have not confined ourselves to considering only the adverse effects specified by UR or the remedies proposed by UR, nor to examining points of difference between UR and PNGL. We emphasize that our task does not begin with a consideration of UR's proposals, or PNGL's objections to them, but with the current licence conditions and that we are only required to consider possible remedies (and therefore changes to the current licence conditions) if we find that the current conditions are against the public interest.
- 3.24 In its price control review in 2011, UR made adjustments to take account of inflation, new capitalized expenditure and depreciation. These proposed adjustments were not challenged by PNGL. Nonetheless, we considered whether the matters they sought to remedy operate or may be expected to operate against the public interest before deciding that those proposals should be approved.
- 3.25 One issue between PNGL and UR was a net reduction proposed by UR to the total regulatory asset value shown in Licence Condition 2.3.18, as £312.8 million for the formula year 2006. The regulatory value is the regulatory asset base on which PNGL earns a return, and UR considered that it was necessary to make a net deduction of £74.4 million (at 2010 prices) in respect of historic unspent allowances to the updated TRV, in order to create the proper long-term link between the amount customers pay and the amount PNGL has spent. We addressed this matter as we were required to consider whether the current TRV operates or may be expected to operate against the public interest.
- 3.26 UR, in the calculation of the 2006 TRV, included separate figures for opex and capex outperformance, deferred capex, WCA outperformance and volume underperformance. The 2012 TRV adjustment included adjustments to each of these components other than grants (ie for opex and capex outperformance, deferred capex, WCA outperformance and volume underperformance). From reviewing the parties' various submissions, it appears to us that there are distinguishing factors in each of these categories. We therefore assessed them separately.
- 3.27 We have assessed issues relating to the treatment of outperformance (including WCA outperformance and volume underperformance) in Section 5, and deferred capex in Section 6. We have then considered the allowed rate of return in Section 7. We have also looked at the implications of regulatory uncertainty and the cost of capital in Section 8. We have addressed whether an overall adjustment to the TRV is warranted on the grounds of the balance of the public interest in paragraphs 9.43 to 9.55.
- 3.28 We are conscious that although many of these issues have required us to consider previous determinations by UR, the questions in hand relate to the determination for 2012 and 2013. Therefore, whilst we have not revisited those previous determinations, we have referred to them to help determine what judgement might be appropriate in determining whether the current licence conditions may or may be expected to operate against the public interest.

4. Gas customers

Introduction

4.1 In this section we outline the position of natural gas customers, both domestic consumers and industrial and commercial (I&C) customers.

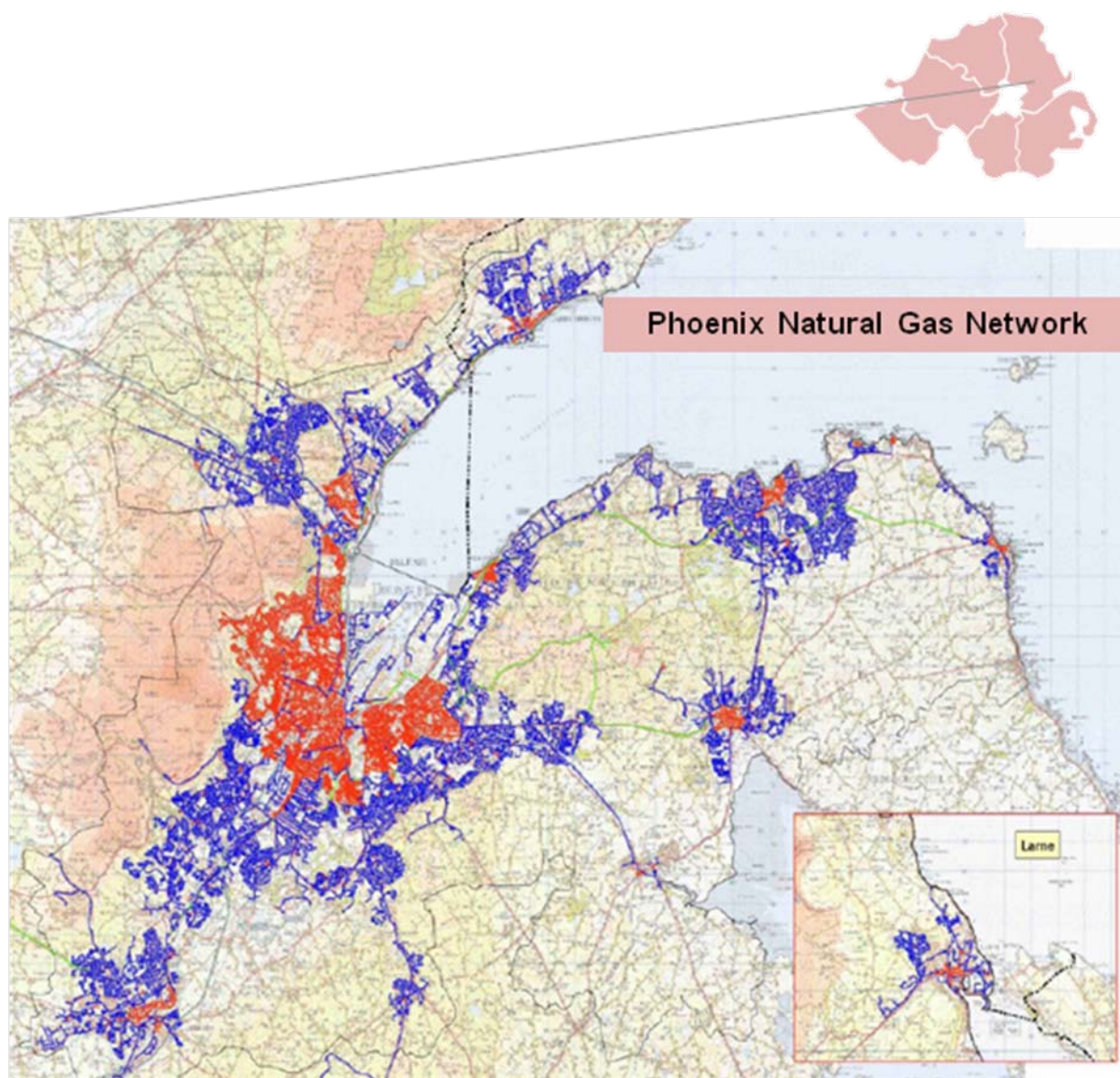
The PNGL Licensed Area

4.2 The PNGL Licensed Area for the distribution of natural gas covers Greater Belfast and Larne, which account for approximately 40 per cent of the population of Northern Ireland—see Figure 2.1.

4.3 The PNGL gas distribution network built since 1996 is shown in Figure 4.1.

FIGURE 4.1

PNGL's gas distribution network



Source: PNGL.

Note: The low-pressure network is shown in red and the medium-pressure network in blue.

- 4.4 The PNGL Licensed Area covers a significant proportion of the population of Northern Ireland: of the total population of about 1.8 million, around 650,000 live in the Greater Belfast area.
- 4.5 The total number of properties in PNGL's Licensed Area is around 330,000,¹ of which about 310,000 are domestic properties and about 20,000 are I&C properties.
- 4.6 PNGL's 1996 licence contained a mandatory development plan which specifically required PNGL to develop a sustainable network through which natural gas was available to no less than 81 per cent of all properties within its Licensed Area within a fixed rolling timescale.
- 4.7 At the end of 2011, PNGL had passed about 88 per cent of properties in its Licensed Area, ie PNGL had made natural gas available to nearly 292,000 of the about 330,000 properties in its Licensed Area of which about 273,000 were domestic properties and about 19,000 were I&C properties.
- 4.8 At the end of 2011, just over 148,000 properties in PNGL's Licensed Area had converted to natural gas, of which about 137,000 were domestic properties, and about 11,000 were I&C properties. Therefore, around 50 per cent of domestic properties with access to natural gas within PNGL's Licensed Area had converted to natural gas and a slightly higher proportion, around 60 per cent, of I&C properties with access to natural gas within PNGL's Licensed Area had converted to natural gas.
- 4.9 In terms of PNGL's revenue, about 55 per cent comes from customers using less than 2,500 therms a year (largely domestic consumers and smaller I&C customers). In overall terms, about 50 per cent of PNGL's revenue comes from domestic consumers alone.
- 4.10 UR's 2012 price determination allowed for the passing for natural gas of a further 11,500 properties by PNGL in the next two years. If successful, this would mean that some 92 per cent of the properties in PNGL's Licensed Area would have natural gas available. PNGL told us that increasing the number of passed properties beyond 92 per cent would be subject to an 'economic and efficiency test'. The remaining properties would be likely to be in the harder-to-reach and more rural areas of the PNGL Licensed Area and the cost of providing network may, therefore, be more expensive than in the more densely-populated areas.
- 4.11 New connections to gas continue to run at around 8,000² customers each year, of which around 7,700 are domestic and around 380 are industrial and commercial. At the current rate of connection, it will take about 18 years for all passed domestic properties in the PNGL Licensed Area to be converted and about 21 years for all I&C properties to switch.
- 4.12 The split of the 137,000 domestic properties that had connected to PNGL's natural gas network at the end of 2011 by housing sector is shown in Table 4.1.

¹ PNGL [statement of case](#), Figure 1, p17.

² PNGL [statement of case](#), paragraph 2.10.

TABLE 4.1 Domestic properties connected to PNGL’s natural gas network by housing sector

Owner occupied*	66,617
New build	34,166
NIHE	<u>36,497</u>
Total	137,280

Source: PNGL.

*UR said that this referred to connections of domestic properties that were not new-build or NIHE properties—see UR PNGL12 determination, p5.

4.13 While natural gas availability was around 88 per cent in PNGL’s Licensed Area at the end of 2011, total natural gas penetration in Northern Ireland is estimated at around 20 per cent. In contrast, natural gas penetration in Great Britain stands at some 90 per cent.³

Protecting consumer interests

UR

4.14 UR’s responsibilities in relation to consumers are set out in full in Appendix B.

Consumer Council Northern Ireland

4.15 The main body representing the interests of gas customers is the CCNI. It is an independent consumer organization. Its aim is to make the consumer voice heard and make it count. CCNI has a statutory remit to promote and safeguard the interests of consumers in Northern Ireland and it has specific functions in relation to energy, water, transport and food. These include considering complaints and enquiries, carrying out research and educating and informing consumers.

4.16 CCNI is also a designated body for the purposes of supercomplaints, which means that it can refer any consumer affairs, goods and services issues to the Office of Fair Trading where it feels that the market may be harming consumers’ best interests.

PNGL’s consumer responsibilities

4.17 There is no statutory duty placed upon PNGL towards customers under the Energy Order along similar lines to UR’s duties under Article 14. PNGL does, however, have certain other duties under the Order, in addition, of course, to price controls. Article 41B of the Energy Order requires holders of a gas conveyance licence to comply with the duties imposed under sections 3(4) and 7 of the Energy Act (Northern Ireland) 2011 (the Act).

4.18 Section 3(1)(b) of the Act provides that UR may from time to time determine ‘such standards for overall performance in connection with the activities of gas conveyors as, in its opinion, ought to be achieved by them’. Under section 3(4), PNGL, as a gas conveyor, has a duty ‘to conduct business in such a way as can reasonably be expected to lead to the achievement by that gas supplier or gas conveyor of the standards set under this section’.

4.19 Section 7(1) of the Act imposes a duty on PNGL to:

³ Percentage of homes and businesses in Great Britain which have access to gas. PNGL [statement of case](#), paragraph 2.12.

in such form and manner and with such frequency as the UR may direct, take steps to inform the customers of gas suppliers of—(a) the standards of overall performance determined under section 3 which are applicable to that gas supplier or gas conveyor; and (b) the levels of performance achieved by that gas supplier or gas conveyor as respects each of those standards.

Customer service standards

- 4.20 The basis upon which PNGL's performance is measured is the company's service standards. PNGL's licence requires a number of customer service standards to be adopted. PNGL said that it had gone beyond prescribed standards and had voluntarily operated to a wide-ranging set of 'Standards of Service', which were endorsed by the CCNI and UR, and were reported on an annual basis.
- 4.21 UR is currently in the process of implementing Guaranteed Service Standards (GSS) for PNGL which are consistent with Great Britain gas distribution operators as well as the local electricity infrastructure company, Northern Ireland Electricity.

Safety obligations on consumers and PNGL

- 4.22 PNGL's gas supply and operations are subject to a number of laws and regulations which require PNGL to operate in a safe and responsible manner. The principal enforcement agency is the Health and Safety Executive for Northern Ireland (HSE (Northern Ireland)). Such laws and regulations include the following:
- Health and Safety at Work (Northern Ireland) Order 1978;
 - Gas Safety (Management) Regulations (Northern Ireland) 1997; and
 - The Pipelines Safety Regulations (Northern Ireland) 1997.
- 4.23 The key safety obligations on PNGL are imposed by the Gas Safety (Management) Regulations (Northern Ireland) 1997 which require PNGL to prepare a safety case and that this safety case is accepted by the HSE (Northern Ireland). PNGL has met this requirement. The safety case gives details of PNGL's operations and describes the measures taken to ensure the safe management of gas within its system. PNGL has to carry out a review of its safety case at least every three years, and submit to the HSE (Northern Ireland) a written report of the review, even if there are no material changes.
- 4.24 PNGL is obliged to provide certain emergency services under these regulations and under its licence, including establishing and maintaining emergency telephone services and attending to gas escapes within 12 hours. PNGL provides a 24-hour, 365 days a year emergency response service to deal with public reported escapes (PREs). PNGL's standards of service for dealing with PREs is to attend the relevant site within 1 hour for all uncontrolled (suspected release of gas cannot be isolated via the customer control valve) PREs and within 2 hours for all controlled (suspected release of gas can be isolated via the customer control valve) PREs. PNGL provides this service through a combination of resources from its subsidiary, Phoenix Energy Services, from its contractor McNicholas Construction Services Limited (McNicholas) and from its own direct labour.
- 4.25 Article 60 of the Gas Order also places responsibilities on owners of gas networks. In summary this includes obligations:

(1) to make arrangements, in the event of the accidental escape or ignition of any gas in the line, to ensure immediate notice is given to the Northern Ireland Fire & Rescue Service Board; the Police Service of Northern Ireland; and any other body which the Department so requires; and

(2) to provide maps and information to enable the relevant body to carry out its duties.

- 4.26 The basis upon which PNGL's performance is measured is the company's service standards. As noted above, PNGL's licence requires that a number of customer service standards be adopted. PNGL has gone beyond the prescribed standards and has operated to a wide-ranging set of Standards of Service, which are endorsed by CCNI and UR.
- 4.27 PNGL's Standards of Service results are reported on an annual basis. In the five years from 2007 to 2011, there were some 100,000 asset management and emergency response jobs undertaken at customer premises as well as some 45,000 new connections to PNGL's distribution network. PNGL told us that this activity resulted in 23 complaints to the CCNI.
- 4.28 In 2002, a CCNI report⁴ suggested that some 20 per cent of customers surveyed were dissatisfied with some aspect of the gas installation. CCNI's 2012 report showed less than 5 per cent dissatisfaction.

Increasing the availability of natural gas in Northern Ireland

- 4.29 The DETI's Strategic Energy Framework set out its objectives for gas network extension where it is technically possible and economically viable⁵ to do so.
- 4.30 Following the establishment of the PNGL and firmus energy gas distribution networks, there is potential for significant numbers of consumers who are already passed to switch to natural gas and there is also scope to connect further households within the licence areas through infill of areas within the licence area that are not currently supplied. Potential also exists for further extension of the supply of natural gas in Northern Ireland into areas in the West of Northern Ireland and beyond.
- 4.31 In the PNGL licence area there are still some 136,000 households that could be connected to natural gas but which have not switched. Of these 136,000, 125,000 are privately-owned homes and 11,000 are social housing.
- 4.32 PNGL told us that a further 37,000 homes had the potential to be connected to the gas network subject to the economic and efficient assessment, but which were not yet served by the distribution network. Of the 37,000, 30,000 were privately owned and 7,000 were social housing.
- 4.33 PNGL also told us that there were some 15,000 properties adjacent to the PNGL licence area which it believed could be connected. In addition there were 2,000 to 3,000 new-build homes each year in its licence area which could be connected to natural gas.

⁴ www.consumercouncil.org.uk/energy/publications-and-research/.

⁵ DETI response to provisional determination.

- 4.34 In total there are estimated to be some 280,000 domestic properties in the firmus energy licence area. Currently, about 50,000 domestic properties in the firmus energy licence area have access to their distribution network. Of these 14,500 households have been connected to the natural gas network and 13,000 have switched to natural gas. There is the potential, therefore, for another 37,000 households who currently have access to the firmus distribution network to connect and switch to natural gas.
- 4.35 UR told us that 105,000 properties were forecast to be passed in the firmus energy area by 2036 and that the firmus licence was granted on the basis that this was the maximum number of properties which could be reached on a commercially viable basis. UR also told us that other options to pass a higher proportion of properties were net present value (NPV) negative.
- 4.36 UR highlighted that should circumstances change and more properties become commercially viable to pass, this would be covered through the price control process. UR was satisfied that such investment would be delivered based on commitments made by firmus since 2005 and in particular in the last year since PNG12 was published.
- 4.37 There are around 6,400 I&C customers in the firmus licence area. Of these 1,700 have been connected to the natural gas network and 1,500 have switched to natural gas. There is the potential, therefore, for some 4,900 further I&C customers to connect and switch to natural gas.
- 4.38 Taking all the figures together in terms of infill and expansion in the current PNG12 and firmus licence areas there may be potential for around a further 290,000 properties to connect to natural gas. At the second hearing with PNG12, it indicated that such an expansion would require £400–£500 million of investment. UR said that distribution companies had an obligation to connect all readily connectable properties as set out in the relevant connection and policy licences. UR said that this covered the majority of properties left to be connected.
- 4.39 In addition there are also plans which are subject to technical and economic assessments for further expansion of the gas network.
- 4.40 DETI,⁶ in conjunction with UR, undertook a detailed technical and economic feasibility study concerning gas extension to the West of Northern Ireland and this was published in 2010. In 2011, DETI also undertook a detailed public consultation on gas extension. DETI is now in the process of completing a more detailed business case for gas extension into towns in the West and North-West of Northern Ireland, and in East Down. The towns and villages to be covered would be:
- Dungannon;
 - Cookstown;
 - Magherafelt;
 - Omagh;
 - Enniskillen/Derrylin;

⁶ All information taken from slides on the DETI website:
www.uregni.gov.uk/publications/extending_gas_network_in_northern_ireland_deti_presentation_slides_june_2011.

- Strabane;
- Downpatrick;
- Ballynahinch;
- Hillsborough;
- Saintfield;
- Crossgar; and
- Ballygowan.

4.41 The cost of providing gas transmission networks to all six towns identified within the 2010 study (Dungannon, Cookstown, Magherafelt, Omagh, Enniskillen and Strabane) was estimated at around £75 million. It would cost an extra £10 million to take gas to Derrylin. The respective gas distribution networks were estimated to cost between £26 million for a network covering just I&C properties and £86 million covering both I&C and domestic properties. If the shortfall in the cost of funding the new gas transmission to the West was funded entirely by the postalized gas transmission tariff,⁷ gas transmission tariffs in Northern Ireland could increase by 14.7 per cent as a result.

4.42 On UR's website the outline timetable for the expansion of gas into other areas is given as:

- May 2012—consultation on licensing issues (UR);
- Summer 2012—completion of business case (DETI);
- Autumn 2012—engage with the Department of Finance and Personnel (DFP) and Northern Ireland Executive (DETI);
- 2013—award of licences for new gas areas (UR);
- 2013–2014/15—network design, planning, environmental assessments;
- 2015—construction of main gas transmission pipes; and
- 2015/16 onwards—build new gas distribution pipelines and connect new customers.

4.43 DETI confirmed that the aim was to have a new gas transmission network in place during 2015, followed by roll-out of the gas distribution networks in individual towns over a number of years.

4.44 UR told us that it was currently considering what kind of model would be appropriate for a new licensed area, but it said that it would be a standard regulatory model quite similar to the current PNGL and firmus frameworks.

⁸ ie if the expansion of the gas transmission network was funded by the users of the existing gas transmission network.

- 4.45 In terms of domestic users, expansion to the West would connect a maximum of just over 31,000⁸ households. Such a connection rate has the potential to generate maximum demand for about 22 million⁹ therms of natural gas. This is about 40 per cent of the natural gas therms demanded by domestic consumers currently using natural gas in the PNGL licence area.
- 4.46 In addition, there are a number of large I&C potential gas users in the West which would benefit from access to the gas network. The I&C customers could generate demand for about 30 million¹⁰ therms of natural gas if all of them connected to the network and switched to natural gas. The UR modelling assumed a connection rate of 80 per cent, so roughly a potential 25 million therms per year would be demanded from the extension of gas to the West by I&C users. This compares with PNGL estimates that approximately 60 to 70 million therms are used by I&C users in PNGL's Licensed Area, with volumes likely to be toward the upper end of this range.
- 4.47 UR said in its submissions that any expansion of gas to the West would require a subvention/subsidy from Government for the establishment of the transmission pipeline (large pipes above 7 bar pressure) and that this was subject to a decision from the Northern Ireland Executive. As and when this decision was made, UR said that it had already spent a considerable amount of effort to progress a licence award.
- 4.48 A letter¹¹ received from DETI in response to the CC's provisional determination indicated the benefits of the extension of natural gas to the West. The DETI response noted that the proposed extension of the existing natural gas pipeline would contribute to the following objectives, in line with European National and local policies:
- increasing the competitiveness of businesses operating within and near to selected towns (on the proposed route);
 - reducing fuel poverty in the selected towns;
 - reducing Northern Ireland's carbon footprint through reduced CO₂ emissions; and
 - reducing Northern Ireland's exposure to fluctuating oil prices.
- 4.49 The DETI letter of 3 September noted that the first three of these objectives aligned very closely with the first three priorities of the Northern Ireland Executive's Programme for Government (2011–2015):
- Priority 1: Growing a sustainable economy and investing in the future.
 - Priority 2: Creating opportunities, tackling disadvantage and improving health and well-being.
 - Priority 3: Protecting our people, the environment and creating safer communities.
- 4.50 The DETI letter also asked the CC to note that on 3 September the Northern Ireland Executive discussed and endorsed the Investment Strategy for Northern Ireland (ISNI) for the period 2011–2021. It said that this was the key infrastructure framework for the Northern Ireland Government and it included support for gas network

⁸ Feasibility Study Summary Report published March 2010, Table 1.2-2.

⁹ *ibid*, Table 1.5-1.

¹⁰ *ibid*.

¹¹ DETI [response to provisional determination](#).

extension. Specifically it states: 'We will encourage extension of the gas network where it is technically possible and economically feasible to do so, to enhance diversity of fuel supply and customer choice and bring about reductions in CO₂ emissions.'

- 4.51 Rather than the extension of the gas network beyond current licence areas the CCNI placed greater emphasis on extending the reach of gas within areas where there were already distribution licences. Lord Whitty undertook an independent review at the request of CCNI in 2010 to examine energy policy in Northern Ireland, specifically in relation to affordability, sustainability and security of supply. In the report *Energising Northern Ireland*, published in March 2012, Lord Whitty indicated that while they were not mutually exclusive, priority should be given to consolidation of connections to the existing gas network rather than an expansion. For the south and west of Northern Ireland, Lord Whitty said that the focus should be on the development of renewable fired electricity regeneration for heating because the expansion of natural gas into those areas would not be economically viable.
- 4.52 The Green Party questioned the extent to which there is a likelihood of expansion of the gas network in Northern Ireland. In doing so it cited Lord Whitty's report. The Green Party also highlighted that the Energy Saving Trust and Action Renewables group have asserted that the proposals for expansion of the gas network are not cost effective and ought to be reconsidered.

Costs of energy

- 4.53 17 per cent of the population in Northern Ireland use gas for heating, compared with around 80 per cent who use oil. Submissions on the relative costs of oil and gas accepted that natural gas is generally cheaper than the dominant fuel used for heating, oil, both for domestic and I&C users. The extent of the savings was disputed between various parties, including UR and PNGL, depending on the basis for the comparison. It was apparent that savings could vary over time and indeed we were shown evidence from UR that in October 2009 gas was more expensive than oil.
- 4.54 The DETI letter dated 3 September set out in summary the case for switching to gas where it was economically viable to do so:
- There is widespread acceptance of the benefits of natural gas compared to other more polluting fuels such as oil and coal, and these benefits include cost savings, greater convenience and budget management for domestic consumers in particular, more significant cost savings and the potential for establishing combined heat and power systems for larger business users, and a reduction in greenhouse gases. Natural gas infrastructure can also provide networks for renewable technologies such as biogas, and in many respects can be considered as a transition fuel.
- 4.55 Because of the high cost of oil, CCNI acknowledged that reliance on oil for home heating, as a key energy source for Northern Ireland homes, was a major contributor to high energy bills. Average fuel bills in Northern Ireland were not only much higher than in the rest of the UK but they had risen at a much faster rate since 2001—see Table 4.2.

TABLE 4.2 Average household energy bills, 2001 and 2011

	£		
	Average bill 2001	Average bill 2011	Percentage increase 2001–2011
Northern Ireland	768.55	2,368.71	208
Great Britain	541.33	1,258.09	132
Difference	227.22	1,110.62	389

Source: CCNI (from DECC, CCNI, Sutherland tables, Consumer Focus, Power NI, Phoenix Supply Limited, firmus energy).

4.56 Costs of energy per household in Northern Ireland are, therefore, more than 85 per cent higher than in Great Britain, and since 2001 prices in Northern Ireland have risen by over 75 per cent more than in Great Britain.

Fuel poverty

4.57 Fuel poverty (which is defined as where more than 10 per cent of household income needs to be spent on maintaining adequate heating provision) is much higher in Northern Ireland compared with other parts of the UK. The proportion of households in fuel poverty in 2009 in all parts of the UK and the Republic of Ireland is shown in Table 4.3.

TABLE 4.3 Households in fuel poverty, 2009

	%
England	13
Wales	26
Scotland	33
Republic of Ireland	19
Northern Ireland	44

Source: CCNI (DECC, NI House Condition Survey 2009, RoI Energy Statistics).

4.58 The latest (2009) Northern Ireland Housing Executive's House Condition's survey¹² showed that of the 44 per cent of households in fuel poverty:

- 22 per cent were in marginal fuel poverty (10 to 15 per cent of income needs to be spent on fuel);
- 11 per cent were in severe fuel poverty (15 to 20 per cent of income); and
- 11 per cent were in extreme fuel poverty (over 20 per cent of income).

4.59 Fuel poverty at 44 per cent in Northern Ireland is more than three times as high as in England, around 80 per cent higher than in Wales, one-third higher than in Scotland and more than twice as high as in the Republic of Ireland.

4.60 For disadvantaged groups, the figures are even starker. The 2009 House Condition Survey further showed that 53 per cent of people between 60 and 74 years old, and nearly 76 per cent of people over 75 years old, in Northern Ireland were in fuel poverty. A 2009 study by Hillyard and Patsios¹³ showed that lone parents in Northern Ireland spent 56 per cent of their income on fuel compared with 26 per cent in Britain.

¹² www.nihe.gov.uk/northern_ireland_house_conditions_survey_2009_-_main_report.pdf.

¹³ www.jrf.org.uk/sites/files/jrf/tackling-child-poverty-Northern-Ireland-summary.pdf.

- 4.61 A 2009 report by the Joseph Rowntree Foundation, 'What can we do to tackle poverty in Northern Ireland',¹⁴ found that 48 per cent of children in Northern Ireland were living in poverty at some time over the four-year period investigated (before housing costs), compared with 38 per cent in Great Britain, and 21 per cent were in poverty for either three or four of the years ('persistent poverty'), compared with 9 per cent in Great Britain.
- 4.62 The CCNI estimated that around 302,000 households in Northern Ireland were struggling to heat their homes.
- 4.63 A report by the University of Ulster 'Defining Fuel Poverty in Northern Ireland'¹⁵ said: '...a primary reason for high levels of energy expenditure in Northern Ireland is the prominence of oil as a source of domestic heating fuel.....The predominance of oil as a central heating source has **an overwhelming impact on current heating expenditure.**' [Emphasis added]
- 4.64 The Northern Ireland Executive has said that one of the objectives to be gained from extending the gas network is 'reducing fuel poverty in the selected towns'.

The case for switching to natural gas

- 4.65 We received a number of submissions from the parties setting out the cost of natural gas compared with oil for heating and hot water. The savings in using natural gas vary and are dependent on factors such as the price per unit of the different fuels, the efficiency of boiler, whether comparisons should include the benefits of installing high-efficiency boilers in one or both cases (eg savings can be made from upgrading from a non-condensing oil boiler to a condensing one as well as converting directly from oil to gas) and household consumption. Differentials will also vary over time particularly as prices of the respective fuels fluctuate. Oil prices are subject to almost daily fluctuations in price and there are some 300 unregulated suppliers. It was apparent that there could be little basis for calculating a reliable average cost saving across all households.
- 4.66 However, certainly in recent times, gas per unit has been consistently cheaper than oil. PNGL told us that on 5 September there was a 44 per cent premium on the purchase of a unit of oil compared with an equivalent unit of gas. UR said in a submission in September 2012 that over the previous 12 months oil had been on average 28 per cent more expensive per unit than natural gas.
- 4.67 UR supplied figures based on the Sutherland tables¹⁶ on the comparative cost of heating a three-bedroom house constructed before the 2006 building regulations came into force between using a condensing natural gas boiler and a non-condensing oil boiler. The Sutherland tables assumed that such properties consumed 16,300 kWh of gas a year for heating and hot water and that consumers purchased around 2,600 litres of oil a year and bought their oil in 900-litre refills. UR figures indicated that the annual savings from using a condensing gas boiler against a non-condensing oil boiler for space and water varied from £324 in April 2010, £463 in October 2011 and £512 in July 2012 giving an average over the period of £433 per year. But in October 2009 gas was £11 more expensive than oil per year.

¹⁴ www.jrf.org.uk/sites/files/jrf/tackling-child-poverty-Northern-Ireland-summary.pdf.

¹⁵ [http://eprints.ulster.ac.uk/19994/1/FuelPovertyReport\(WEB\)-5Sept2011.pdf](http://eprints.ulster.ac.uk/19994/1/FuelPovertyReport(WEB)-5Sept2011.pdf).

¹⁶ Sutherland Comparative Domestic Heating Costs Tables have been published regularly since 1976. They compare costs of different heating in the UK divided into regions, including Northern Ireland.

- 4.68 For new-build three-bedroom homes (or homes upgraded to that standard) but still using a non-condensing oil boiler the Sutherland tables assume gas usage of 8,639 kWh a year and 1,610 litres of oil. In such homes savings from switching to natural gas were £201 in April 2010, £285 in October 2011 and £316 in July 2012 giving an average over the period of £267. Again in October 2009 gas was £9 per year more expensive than oil.
- 4.69 The UR tables showed that when converting from an oil-fired condensing boiler to a gas-fired condensing boiler savings were less, at between £122 and £235 a year for an older house and between £69 and £134 for a new-build house between April 2010 and July 2012. In October 2009 oil was cheaper than gas by £122 a year for new builds and £184 for older houses when comparing condensing oil and condensing gas boilers.
- 4.70 Evidence submitted by PNGL suggested that like-for-like comparisons of using gas compared with oil for heating and hot water produced savings of between £235 and £700 a year depending on usage and whether the householder was able to purchase 900-litre refill or purchased oil in smaller quantities down to 20-litre oil drums. When savings from moving from an old-style oil condensing boiler to a high-efficiency gas boiler were factored in PNGL estimated the savings at between £540 and £1,200 year.
- 4.71 The issue of consumers purchasing refills of less than 900 litres was also addressed to some extent in the publication 'Defining Fuel Poverty in Northern Ireland'¹⁷ which said:
- Oil has the added disadvantage of having to be bought in advance of being used. This places an extra burden on low income households, for whom a single oil purchase may comprise more than a month's disposable income. **Families experiencing fuel poverty are increasingly reliant on purchases of small quantities of fuel at inflated prices, which further increases expenditure relative to income.** [Emphasis added]
- 4.72 On 27 March 2012 Antoinette McKeown, Chief Executive of the CCNI, said in relation to consumers buying 20 litre refills: 'The Consumer Council is aware that many households in NI choose to purchase emergency 20 litre oil drums, yet someone reliant on these drums will spend on average £800 more annually than someone who buys approximately five and a half, 500 litre fills.'
- 4.73 In February 2012 The BBC¹⁸ undertook a price comparison for those paying for oil at different levels of refill. The figures are stark:

¹⁷ *ibid.*

¹⁸ www.bbc.co.uk/news/uk-northern-ireland-16916434.

TABLE 4.4 BBC survey of costs of oil refills

<i>Cost comparison</i>	
<i>Purchase quantity</i>	<i>Price (pence per litre)</i>
20 litre drum	100
200 litres	78
500 litres	60
900 litres	58

<i>Relative annual costs of heating and hot water</i>	
<i>Household buying 2,760 litres a year</i>	<i>Energy bill £</i>
138 (20-litre drums)	2,760
200-litre deliveries	2,152
500-litre deliveries	1,656
900-litre deliveries	1,600

Source: BBC Survey www.bbc.co.uk/news/uk-northern-ireland-16916434.

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- 4.74 It is clear then that for those buying oil in smaller than 500-litre refills there is a significant premium. Consumers converting to natural gas who opt for a pay-as-you-go meter can top up frequently without a significant cost premium.
- 4.75 Combining the Sutherland figures for oil usage in July 2012 and the price indicators in Table 4.4, consumers living in an older-style three-bedroom house converting from filling a non-condensing oil boiler with 20-litre refills to a gas condensing boiler would save around £1,600 a year if they refilled their oil supplies using 20-litre drums the whole year. Refilling storage tanks the whole year on that basis seems unlikely but for those who do have to purchase oil in such volumes, perhaps in a cold snap, the premium is very high.
- 4.76 Perhaps more likely is using 200-litre refills and on that basis consumers would save around £1,000 a year when converting from a non-condensing oil boiler to a condensing gas boiler
- 4.77 In new-build properties¹⁹ the savings would be less—converting from a non-condensing oil boiler with 20-litre refills to a condensing gas boiler would produce savings of around £1,000, and for 200-litre refills around £600. We recognize that these will be maximum savings and that low-income families will almost certainly vary the refill volumes purchased and that purchasing patterns may not be uniform throughout the year, so accordingly savings will vary.
- 4.78 One may also speculate that given the high cost of heating oil to those in fuel poverty, especially when buying in low refill volumes, the potential savings may also be reduced because households are not currently using as much oil as needed to heat the average home. In such circumstances the maximum savings may not be achieved but those in fuel poverty would be able to better afford to heat their homes more adequately. For the young and the old living in fuel poverty this may be particularly important.
- 4.79 In producing its own analysis of heating costs CCNI assumes that around 80 per cent of Northern Ireland households use an old-style non-condensing boiler so savings may be at the higher end of the figures for most of those who convert directly from oil
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¹⁹ See paragraph 4.68.

to natural gas. However, legislation now requires that other than in exceptional circumstances all new boilers, gas or oil, must be condensing boilers, so the question for many people when the lifespan of their current non-condensing oil boiler comes to an end is should they upgrade to a condensing oil boiler or, if it is available, should they switch to natural gas. We were told that in general terms condensing oil boilers were more expensive than condensing gas boilers, but overall the cost of upgrading to a new condensing oil boiler or converting to a new condensing gas boiler were similar.

- 4.80 The purchase of smaller refills than 500 litres of oil for low-income families is to some extent consistent with the high number of consumers that switch to natural gas from oil and in doing so opt for a pay-as-you-go meter so that they can continue to pay for heating and hot water without the need to pay quarterly or even monthly.
- 4.81 It is apparent, therefore, that the savings from converting from oil to natural gas are variable, and indeed in October 2009 oil was cheaper for those who were purchasing oil in 900-litre refills but not, it would seem, for those using 20-litre or 200-litre refills.
- 4.82 Domestic users converting from oil to natural gas can make savings within a very broad range depending on their individual circumstances. It is also clear that householders on lower incomes who are currently using oil for heating and hot water will be paying a high premium if they purchase oil in lower refill volumes. Even if such consumers were to convert to a more efficient condensing oil boiler they would still have to pay a premium for their oil if they continued with smaller refills. For consumers in an average three-bedroom property switching from oil to natural gas with, in all likelihood, a pay-as-you-go meter, would enable them to pay for their energy needs on a daily/weekly basis and produce annual savings of varying amounts of anything up to £1,600 depending on the age of their home, the volume of oil used, the type of oil boiler (condensing or non-condensing) from which they are converting and the volume of oil refills that were being purchased for the oil boiler.
- 4.83 It is certainly also the case that consumers can make savings by upgrading from a non-condensing oil boiler to a condensing one and taking other important heat efficiency measures, for instance insulation. That said there are a number of benefits to consumers from switching directly from an oil boiler to a natural gas condensing boiler including, since April 2010, gas costs were lower compared with oil (whether using a non-condensing or condensing oil boiler), as well as the ability to pay for heating and hot water on a pay-as-you-go basis without paying a significant premium as is the case with oil. Gas is also cleaner and more environmentally friendly.
- 4.84 In summary incentivizing more connections to, and extending, the gas network where it is technically and economically possible to do so, would have a number of benefits including reducing fuel poverty. The case for natural gas was well summed up in the DETI letter dated 3 September:

Natural gas provides greater convenience and costs benefits to domestic consumers and, while there can be a level of debate around the precise scale of savings, the Department considers that widespread usage of gas pre-payment meters is evidence of how gas consumers, and particularly those in fuel poverty, can more easily budget for the energy needs with natural gas compared to other fuels.'

Industrial and commercial customers

- 4.85 About 45 per cent of PNGL's revenue comes from larger I&C customers (using over 2,500 therms a year). When I&C customers using less than 2,500 therms a year are

added in, as indicated earlier, the split between I&C and domestic customer revenues for PNGL is roughly 50/50.

- 4.86 Energy costs are significant for I&C customers in Northern Ireland. Several parties submitted to us that higher energy costs impacted on the competitiveness of business in Northern Ireland.
- 4.87 The Northern Ireland Independent Retail Trade Association indicated that energy costs could form some 25 per cent of companies' operating costs and that if Northern Ireland businesses were to compete with others in the UK and the Republic of Ireland, then competitive energy costs were essential.²⁰
- 4.88 John Thompson and Sons Ltd also indicated that since privatization of energy generation in Northern Ireland, large energy users had consistently seen an energy cost premium of between 25 and 30 per cent compared with England.²¹
- 4.89 The Northern Ireland Federation of Small Business Member Survey published in February 2012 noted that around half of Northern Ireland members claimed to be impacted by the increased cost in raw materials, fuel and energy. The same survey found that, compared with members across the UK, significantly more Northern Ireland members were affected by the increased cost of raw materials, fuel and energy.
- 4.90 Based on PNGL's desktop analysis and considered view of the average price paid by large I&C customers in 2011, the potential savings for its top 20 customers (by volume in PNGL's Licensed Area), having chosen natural gas over gas oil, would be, on average, about £0.5 million a year. This ranges, however, from potential savings of about £160,000 up to about £1.6 million a year.
- 4.91 For larger I&C energy users the benefits of converting to natural gas from oil are, therefore, clear with savings of up to £1.6 million a year. This benefit is borne out by the fact that we were told by UR that larger I&C customers in the PNGL licence area who could do so had already converted to natural gas. PNGL subsequently confirmed this but noted that there were still some slightly larger ones such as schools, police stations, nursing homes and office blocks that had not connected, but said the majority of its new I&C connections were at the small end.
- 4.92 In terms of the benefits of extending the gas network, again it is worth noting that DETI, whose remit includes economic development in Northern Ireland, has said that one of the benefits was that it would increase the competitiveness of businesses in the selected towns.

Converting to natural gas

Process

- 4.93 There are two distinct elements in the processes of customers switching to natural gas: connection to the natural gas network and conversion of their existing fuel source. Connection to the natural gas network involves PNGL running a gas supply to the property. PNGL installs a service and meter at the property free of direct charge to the consumer. Conversion is where the property occupier converts from their existing fuel source to natural gas. The customer chooses an installer to

²⁰ Northern Ireland Independent Retail Trade Association [initial submission](#).

²¹ John Thompson and Sons Ltd [initial submission](#).

undertake the conversion. The installer installs the heating system and domestic appliances where appropriate.

- 4.94 In addition, customers have the option of choosing their supplier in PNGL's Licensed Area, where the natural gas supply market is now open to competition. There are currently two natural gas suppliers to domestic properties in PNGL's Licensed Area: Airtricity²² and firmus energy. I&C customers can be supplied by Airtricity, firmus energy, Energia, Oni Gas Ltd, ESB Independent Energy (NI) Ltd (Electric Ireland) or Vayu.

Grants

- 4.95 There are a range of grants available to consumers switching to natural gas.
- 4.96 The Northern Ireland Sustainable Energy Programme (NISEP) is funded by electricity customers in the form of a Public Service Obligation. The NISEP includes grants to help consumers improve their energy efficiency, which includes grants to install or upgrade efficiency of heating systems. The funding for 2012/13 is just over £7.9 million. Funding is allocated each year following a bidding process, and schemes are awarded funding on the basis of cost-effectiveness. Any organization that meets the criteria set out in the NISEP Framework Document can apply to become a Primary Bidder and therefore compete for funds. 80 per cent of NISEP funds are allocated to schemes targeted at priority (that is vulnerable, ie low-income) customers. For 2012/13, the total funding for the priority group was £6.3 million (out of the total funding of £7.9 million). The schemes that subsidize gas connections are all aimed at priority consumers, although some are fully funded and others require a customer contribution. 34 per cent of total NISEP funding is available for providing whole-house solutions (at least half of which should go to schemes which do not require a customer contribution), ie full packages of heating systems and insulation measures (and, if appropriate, renewables). The majority of schemes within the priority group have good uptake and most of the funds are spent each year. The schemes funded for 2012/13 that support low-income households installing gas heating include:
- Energy Saver Homes—undertaken by Power NI (total funding available: £1,011,163). Fully-funded scheme that covers the whole of Northern Ireland and provides gas heating on the gas network and oil heating off the network.
 - Toasty Homes Plus—undertaken by firmus energy (£715,460). Fully-funded scheme, firmus contributes £300 to each installation. It covers households on the firmus energy gas network.
 - Toasty Homes—undertaken by firmus energy (£1,270,206). Part-funded scheme, approximately 50 per cent of heating installation costs and 100 per cent insulation costs, firmus contributes £300 to each installation. It covers households on the firmus energy gas network.
 - Snug Plus—undertaken by Power NI (£269,024). Part-funded scheme, £1,500 towards the installation of a natural gas heating system and up to £800 towards cavity and/or loft insulation for qualifying households on the PNGL network.

²² PSL was purchased by Airtricity in June 2012.

- Snug Plus Oil—undertaken by Power NI (£183,693). Part-funded scheme, £800 towards the installation of a natural gas heating system and up to £800 towards cavity and/or loft insulation for qualifying households with old oil systems (over 15 years) on the PNGL network.
 - Cosy Homes—undertaken by Power NI (£552,860). Part-funded scheme for Housing Association properties, £1,000 towards heating system, covers the whole of Northern Ireland and provides gas heating on the gas network and oil heating off the network.
 - Cosy Homes Shelters—undertaken by Power NI (£149,488). Providing natural gas heating communal boilers in three housing association properties (142 residential properties, £1,000 each).
- 4.97 In addition to these schemes, the gas companies have their own offers and incentives to encourage people to convert, for instance, PNGL currently offers up to £400 via an oil boiler scrappage scheme. PNGL also has a £200 ‘cash-back’ offer to domestic owner occupiers with no heating or an existing central heating system fuelled by LPG, oil, solid fuel or electricity (storage heaters) which installs an A-rated high-efficiency natural gas condensing boiler and full controls upgrade where appropriate.
- 4.98 PNGL does not charge consumers directly for standard connection of a property (first-time connections) to its natural gas network including the meter installation. This is currently said to be worth up to £750 in total for a domestic customer.

Barriers to converting to natural gas

- 4.99 The ‘town gas’ industry had ceased in Northern Ireland in the 1970s and the network was decommissioned in the 1980s. That means that there is no real history of using gas for heating in Northern Ireland and consumer confidence must be built from a very low base.
- 4.100 We were told by both main parties that natural gas was still a relatively new fuel to most Northern Ireland consumers and that there was a significant job to be done to ‘sell’ the fuel to the Northern Ireland public. The use of oil, we were told, was ingrained and there was a reluctance and mistrust of converting to natural gas, even apparently in homes where income might be well above the average and so the conversion costs would be more affordable.
- 4.101 The May 2012 report by CCNI, *Customers’ Experience of Natural Gas in Northern Ireland*, indicated that the key reason which would persuade people in Northern Ireland to switch to natural gas was price; some 95 per cent of respondents gave this as the reason for switching if they could. Among those who have had natural gas installed, some 35 per cent said that price was the reason and 51 per cent said it was easier to use and provided instant heat. Some 30 per cent said that it was cleaner or more convenient.
- 4.102 This suggests that the main driver to converting to natural gas is convincing domestic consumers that gas is cheaper, cleaner and more convenient.
- 4.103 The costs of converting a typical property to natural gas are between £2,000 and £3,000. This includes, for example, the costs of removing the old oil system, installing a new gas boiler, flue etc. PNGL told us that this was the typical cost of around 75 to 85 per cent of all the domestic conversions. Costs would vary by the number of radiators required in a property, and whether existing radiators could be used, but

additional basic costs would be relatively marginal. Costs would also be increased by individual choices, such as having a new gas cooker or fire installed etc.

- 4.104 However, PNGL told us that the majority of installations covering a new gas boiler and usable radiators (either using existing radiators—which would usually have new individual heating controls fitted as part of the installation—or new radiators) would fall within the £2,000 to £3,000 typical cost for a wide range of property sizes with only particularly large houses costing significantly more.
- 4.105 An Office for National Statistics Survey²³ indicated that in 2011 Northern Ireland was the lowest-earning region of the UK with median gross full-time weekly earnings of £451, compared with an equivalent UK average of £500. In London the figure was £651, in Scotland £489 and in Wales £454. Given the comparatively low earnings in Northern Ireland, finding the necessary funds from within their own resources to pay for conversion to natural gas may be difficult or impossible for many households.
- 4.106 Paradoxically, low-income owner occupiers purchasing oil in smaller than 500-litre refills and who would probably make the most savings from switching to natural gas will, in all likelihood, be those who can least afford the £2,000 to £3,000 outlay to switch to natural gas (or for that matter upgrade to a condensing oil boiler). Low-income families living in social housing and privately rented accommodation will in the vast majority of cases be dependent on others to pay for the conversion.

Fluctuations in the cost of fuel

- 4.107 In September of each year PNGL publishes its conveyance charges for the following calendar year. These, in effect, are the charges to customers for the construction, operation and maintenance of PNGL's natural gas distribution network and are derived from the price control determinations by UR, which dictate the maximum revenue PNGL can recover each calendar year for gas transported through its network. These conveyance charges must be approved by UR prior to publication.
- 4.108 Prices are set to recover the revenue PNGL is allowed to recover from suppliers each calendar year for the construction, operation and maintenance of PNGL's natural gas distribution network as determined by UR at each price control review. Prices are set in advance by estimating usage in the following calendar year. Actual out-turn revenues in a calendar year will, of course, be dependent on total gas usage by customers, which will be affected by factors such as the weather and the actual number of new customers. Adjustments are usually required, therefore, in subsequent years to ensure that PNGL recovers the revenue as determined by UR each year. Aside from revenue adjustments because of actual usage, the only other fluctuations are due to actualization of the RPI and the interest rates (applied to revenue over- or under-recoveries in the prior year) which again must be estimated in advance for the following calendar year.
- 4.109 Over the period 2007 to 2011 PNGL's effective distribution charges were as shown in Table 4.5.

²³ www.ons.gov.uk/ons/rel/ashe/annual-survey-of-hours-and-earnings/ashe-results-2011/ashe-statistical-bulletin-2011.html#tab-Regional-earnings.

TABLE 4.5 **PNGL's effective distribution charge**

<i>pence per kWh</i>				
2007	2008	2009	2010	2011
1.21	1.27	1.36	1.25	1.35

Source: PNGL.

Note: The price is the average across all domestic customers.

4.110 The supply price (the price the consumer pays to suppliers based on their gas usage) is made up of this distribution charge, a commodity charge (ie the price for natural gas), a charge for running the supply business etc. Mainly because of fluctuations in commodity costs, the supply price is subject to more variation than PNGL's distribution charge. Table 4.6 shows the supply price which domestic consumers were charged between April 2007 and May 2011 by the gas supplier PSL.

TABLE 4.6 **Supply price data**

<i>pence per kWh</i>					
<i>April</i>	<i>May</i>	<i>Oct</i>	<i>Jan</i>	<i>Oct</i>	<i>May</i>
<i>2007</i>	<i>2008</i>	<i>2008</i>	<i>2009</i>	<i>2009</i>	<i>2011</i>
3.66	4.71	5.63	4.37	3.53	4.93

Source: PNGL.

4.111 Based on the figures in Tables 4.5 and 4.6, between 2007 and 2011 the PNGL distribution charge represented about 28 per cent of the final price charged to consumers for their gas.

4.112 The UR's Energy Retail Report 2012, shows a comparison of average annual bills for a gas customer on standard credit tariffs (distribution charges are only a part of the total customer prices) for natural gas in Northern Ireland as compared with an average for Great Britain.²⁴ Charges in Northern Ireland have been lower than in Great Britain since April 2012 but there has been considerable volatility in relative prices over time. Compared with the most recent available prices for other countries in Europe (June–December 2011), including taxes,²⁵ UR reports that the chart shows that Northern Ireland gas prices are among the lowest in Europe. However, for the reasons given in paragraph 9.88, this does not tell us whether distribution charges are at an appropriate level.

Cost and impact of UR's price control

4.113 UR has indicated that the 2012 price control would reduce average household gas costs by £10 a year against current prices (19p a week). However, without UR's proposed TRV adjustment, prices would increase by £6 a year (about 12p a week) compared with current prices.²⁶ These figures are indicative only as the exact quantum of savings is very sensitive to the assumptions used in the calculation.

²⁴ See [Energy Retail Report 2012](#), Figure 37.

²⁵ *ibid*, Figure 38.

²⁶ These figures differ from the calculation in paragraph 9.96 where we set out our estimates of the effect on average household gas costs of the 2012 price control with and without TRV adjustments. The differences between our and UR's calculations arise largely because UR uses an estimate of actual charges levied in 2012 before the impact of the PNGL12 determination, whereas we used data from the PC03 determination. Also, we believe that UR's calculation does not use the same price base for the charges before and after the PNGL12 determination.

- 4.114 UR estimated that, as with domestic users, I&C users would pay around 2 to 3 per cent less each year for gas for the next 35 years up to 2046 as a result of UR's PNGL12 determination.
- 4.115 UR also told us that because of the fluctuations in energy use and cost by business type (and size), it was not practical, as it was with domestic consumers, to calculate the average savings in cash terms that would be made by I&C users from UR's proposals. However, UR told us that compared with having no TRV adjustment, the very largest customers (of which UR said there may only be two) would pay over £100,000 a year more compared with current prices, and around 20 companies would pay an extra £10,000+ a year.
- 4.116 However, as has been indicated above, energy costs are a significant cost to Northern Ireland businesses and their energy costs are higher than competitors' costs in both the Republic of Ireland and the rest of the UK, so this could be an important factor in competing with businesses in the rest of the UK and the Republic of Ireland. This point was raised in a number of third party submissions to the CC by businesses.
- 4.117 The Belfast Social Care and Health Trust in its response to the provisional determination urged us to consider the impact of the PNGL12 decision on large I&C customers who represent approximately 50 per cent of the gas market. In particular, the Trust expressed concern that the PNGL12 decision may bear upon public finances which are stretched, and upon domestic vulnerable consumers whose health may deteriorate and place greater pressure on the healthcare system.

Questions raised by CCNI

- 4.118 CCNI raised a number of concerns with us about issues other than the disputed TRV. We very briefly outline these below.

Advertising, marketing and PR

- 4.119 CCNI questioned the appropriateness of the allowance to PNGL for advertising, marketing and PR.
- 4.120 UR recognized that allowing advertising and marketing into the PNGL cost allowance had added significantly to the size of the PNGL asset base, but had helped the company to meet its connection targets. UR calculated the value of these allowances at around £37 million (2010 prices) since 1996 (increasing to about £50 million when the costs of manpower, for instance sales staff and corporate overheads, were taken into account). On balance, UR decided that it was appropriate to make allowances for promoting the gas industry given its principal objective in gas and the challenges of growing the market. However, in the PNGL12 determination it considered it appropriate to move to an output-based mechanism that would still grant PNGL an allowance, but only for connections actually achieved. In the medium to long term, UR envisaged reducing this allowance downwards, with the possibility of eventually doing away with it altogether at some point in the future.
- 4.121 We accept UR's decision to make an allowance for advertising and marketing in the 2012 determination. We think that this has in the past contributed to encouraging connections and we think that it is appropriate to incentivize PNGL in 2012 and 2013 to make connections, considering UR's duties to promote the development of the gas

industry. We have seen no evidence that it is against the public interest to make this allowance for the period of 2012 and 2013 and note that this allowance was not in dispute between UR and PNGL. However, we make some recommendations to UR when it makes its next charge control determination in respect of PNGL's overall connections incentives in paragraphs 10.47 and 10.48.

PNGL does not operate an asset register

- 4.122 CCNI expressed concerns that PNGL did not operate an asset risk management system, which it suggested might result in consumers overpaying for network maintenance.
- 4.123 In its determination, UR decided to reduce the network maintenance allowance. Furthermore there was an expectation that PNGL would develop a suitable system, and would be monitoring this over the course of the price control. PNGL indicated that it did have an asset management register and system. The point in the determination that the CCNI referred to was that it did not have PAS55 which was the accredited standard for its system. PNGL said that it operated to the principles of PAS55 and was reviewing the appropriateness of obtaining PAS55 during the current charge control period.
- 4.124 We therefore make no further comment.

Service standards

- 4.125 CCNI asked the CC to consider whether the wider public interest would be better served by the PNGL price control being more explicit in linking customer service standards with outputs.
- 4.126 UR said that it had argued for many years that standards of service were an important element of the regulatory regime and should be facilitated through the introduction of the relevant legislation to provide for guaranteed standards. The Act introduced the legislative framework and UR had carried out an extensive amount of work on the back of this significantly to improve standards of service arrangements. This work culminated in the publication of its final proposals in April 2012 for guaranteed and overall standards to apply to the gas industry, including gas distribution companies. This can only be implemented once the relevant regulations are given legislative approval and these are currently with the relevant government department for comment.
- 4.127 The experience of this system could then be used in future to consider if a more direct link with the price control would be appropriate. Given that this process is under way, we make no further comment.

Planning the infill of PNGL's existing network

- 4.128 CCNI asked whether the Northern Ireland public benefited from measures being placed within the PNGL price control that would require PNGL to plan strategically for the infill of its existing network.
- 4.129 Currently PNGL does not have any specific strategic plan for infilling the remainder of its Licensed Area and further discussions are planned between UR and PNGL on this issue. UR made an allowance in the price determination for a further 11,500 connections in the two years of the price control. This would mean that during the PNGL12 price control period, PNGL will have increased the availability of natural gas from 88

to 92 per cent in its Licensed Area. Further expansion of its network within its Licensed Area would be subject to further work to ensure that it was efficient and economic to do so. We therefore make no recommendation on this issue.

5. Outperformance

Introduction

- 5.1 In this section we address the assessment and treatment of outperformance. In particular, we consider how historic outperformance has been accumulated in the TRV.
- 5.2 Outperformance refers to cost or volume performance achieved by a company that is better than the allowances set at a price control. In principle, the regulator sets allowances for costs to cover the price review period. These allowances should be challenging so the company is required to act efficiently. Regulators usually provide a framework for outperformance so that if the regulated company delivers the agreed output at lower actual costs during the period, it achieves an additional profit. In contrast, if it underperforms and incurs higher than expected costs, it has to bear those itself. The pursuit of outperformance is therefore beneficial for the company. However, at the start of the next price control period the regulator can review cost performance in the previous period. Where a regulated company retains all the benefits of outperformance, it is strongly incentivized to lower costs through greater efficiency, which can help reveal to the regulator the level of efficient costs that can be achieved. The regulator can also rely on other sources of information in setting challenging targets, such as its own efficiency assessments and benchmarking against comparator companies. In these ways, tighter cost targets can be set in subsequent price reviews. Consumers benefit if the outperformance reveals to the regulator the possibility of lower future costs than would otherwise be achieved. We refer to this as a ratchet mechanism.
- 5.3 In some cases, the regulator may require that the benefits of outperformance within a price review period are also shared between the regulated company and customers (through lower prices) in some proportion that still provides an incentive to the regulated company to operate efficiently.
- 5.4 PNGL's outperformance in the period 1996 to 2006 was recorded as any underspend relative to allowances. This is reflected in this section where we collectively consider capex and opex outperformance, WCA outperformance, volume underperformance, and deferred capex. In Appendix C we set out some quotes and summaries from UR's and PNGL's submissions in relation to issues relating to outperformance, intended to support this discussion. An evaluation of whether the overall price control conditions operate in the public interest (including whether the inclusion of these elements of historic outperformance in the TRV in the public interest) is set out in Section 9. That assessment draws in part on issues considered in this section.

Past treatment of outperformance

Treatment of outperformance

Pre-2006

- 5.5 The treatment of outperformance is not explicitly set out in the 1996 licence. However, the formulae in the 1996 licence indicated that outperformance accrued in its entirety to PNGL (see paragraph 2.23(e)). PNGL said that at the periodic reviews, its cost and volume forecasts were revised in the light of the out- or under-performance PNGL had achieved up to that point, as well as other information such as operational or comparative assessments of efficiency. Ongoing prices were then

reset on the basis of these cost forecasts. PNGL was allowed under the licence to retain the entire benefit of any outperformance achieved in the price control period,¹ but also bore the risk of underperformance if, for example, it incurred more opex or capex than anticipated.

- 5.6 However, because PNGL's actual revenue recovery was profiled into future years (and because PNGL under-recovered against the revenues it was entitled to charge under the price cap (see paragraph 2.42)), the financial reward for outperformance was not necessarily recovered from customers as it accrued.² Normally, when a regulated company is able to achieve lower than target cost on its opex, it benefits immediately as the allowed revenues it collects exceed the costs incurred. On capex, it recovers revenues based on the rate of return on allowed capex, and there will be financial benefits in subsequent years if the regulated company spends less than the allowance. In PNGL's case, these gains were notional because actual revenues were initially insufficient to finance PNGL's business and so the shortfall of revenues was deferred for later recovery (through deferred revenue). Thus the financial benefits of outperformance that would otherwise have accrued to PNGL was also deferred.
- 5.7 PNGL said that the incentive mechanism applied to PNGL under the 1996 licence exhibited features different to the models that had typically been applied to mature Great Britain networks, in that the incentive applied to capex outperformance was stronger, that is PNGL retained all the benefits of capex outperformance. Under most Great Britain mechanisms, the operator had not been allowed to retain the entire benefit of capex outperformance.³
- 5.8 PNGL said that there were numerous reasons why a higher-powered incentive than standard was appropriate:⁴
- (a) The primary focus of its licence was on providing an incentive to grow the market at least cost, as opposed to driving out historic inefficiencies that had accumulated over decades, which had been the focus of utility regulators in Great Britain. In PNGL's case, by definition, there was no legacy of historic inefficiency to drive out. A higher-powered incentive was therefore required in order to give a strong enough incentive to drive efficiencies that would materially benefit customers.⁵
 - (b) A concern among Great Britain regulators such as Ofgem in the past had been that capex outperformance could be achieved as much by cutting corners as by cutting costs. The stronger the incentive to cut capital costs, the greater the likelihood that the company might allow quality standards to fall, or seek other ways to 'game' the system, in order to beat cost forecasts. In contrast to Great Britain networks, however, PNGL had always been required, as a condition of its licence, to deliver against a pre-agreed set of output measures.⁶ Further, the mandatory development plan incorporated in PNGL's 1996 licence ensured that PNGL had no opportunity to cut corners in rolling out the network. Given these constraints, it was possible to allow a stronger incentive without placing additional risk on customers that the required investment would not be undertaken.⁷
 - (c) The nature of its investment plan meant that it was essentially replicating the same local roll-out a very large number of times. Consequently, it was relatively

¹ PNGL [statement of case](#), paragraph 3.10.

² PNGL [statement of case](#), paragraph 3.14b.

³ PNGL [statement of case](#), paragraph 3.14.

⁴ PNGL [statement of case](#), paragraph 3.15.

⁵ PNGL [statement of case](#), paragraph 3.15a.

⁶ UR stated that no price control had used the development plan as a basis for setting allowances.

⁷ PNGL [statement of case](#), paragraph 3.15b.

uncontentious to determine the inputs (the length of mains of different pressures, service pipes and meters) for each part of the roll-out programme, so the price control process could essentially focus on the unit costs of those components.⁸ This meant that UR could revise the forward-looking capex plans to reflect any cost efficiencies that PNGL had discovered in the previous control period on a unit cost basis. In other words, any generalized outperformance on capex unit costs was relevant information for setting future allowances, which were determined on a unit cost basis. This was harder to achieve in Great Britain as the capex plans of more mature utilities tended to be much less generic, and therefore it was harder to reflect any revealed efficiencies in forward-looking targets.⁹

- (d) The licence and incentive regime had to be designed so that the full package of potential rewards sufficiently outweighed the risks associated with the roll-out of what was a greenfield gas network, and of investing in Northern Ireland in the 1990s. To fail to do so would have meant that investors would have looked for alternative ways to employ the available capital more profitably.¹⁰
- (e) This stronger incentive also protected customers from any cost overruns as PNGL could not recover costs that were above those forecast when the price controls were set. This was an important protection for customers during the construction of a greenfield network.¹¹

Post-2006

- 5.9 UR introduced a rolling five-year capex incentive mechanism in its PC03 determination which applied from 2007. Under this, PNGL is allowed to retain the benefit of future capex outperformance, or suffer the consequences of capex overspends for a rolling five-year period.¹² UR stated that overspend and underspend were thus treated symmetrically under the scheme, provided that PNGL demonstrated to UR that any underspend had been efficiently incurred. UR also noted that there was a retrospective adjustment mechanism introduced as part of PC03 where cost items could be retrospectively adjusted at the time of the next price control (by adjusting the opening TRV), to correct for deviations between forecast assumptions and out-turn activity. It said that the purpose of the retrospective adjustments was to ensure that PNGL was remunerated only for the activities it actually undertook and outputs that it delivered.
- 5.10 For opex, PNGL said that it was allowed to retain the difference between allowed and out-turn opex for the duration of the price control period (in the same way as it was under the 1996 licence). PNGL said that this treatment was less generous than had often been observed in Great Britain, given that there was no rolling retention of opex, which would allow PNGL to retain the benefit of opex outperformance, or suffer the consequences of opex overspends, for a rolling five-year period regardless of when this was achieved within the control period.

⁸ PNGL [statement of case](#), paragraph 3.12, footnote 51.

⁹ PNGL [statement of case](#), paragraph 3.15c.

¹⁰ PNGL [statement of case](#), paragraph 3.15d.

¹¹ PNGL [statement of case](#), paragraph 3.15e.

¹² PNGL [statement of case](#), paragraph 2.56b.

Sources of historic outperformance

- 5.11 UR said that under the 1996 licence, it was apparent from the formulae that charges were based solely on allowed expenditures, ie no mention was made of actual expenditures. Therefore, under the 1996 licence, all past outperformance was fully retained by the regulated company. The formulae do not distinguish between opex and capex outperformance, nor was there any explicit distinction for deferred capex (where rather than a cost saving on capex, there is an underspend on allowances because capex is delayed until a later period or does not occur at all).
- 5.12 In practice, recorded outperformance could arise in a number of ways:
- (a) where the company manages to find a more efficient way of performing its operations. This could, for example, be because PNGL did it at lower unit cost (unit cost efficiencies), or was able to achieve the same output using fewer resources (volume efficiencies);
 - (b) where the original targets set by the regulator are insufficiently challenging; and
 - (c) where the company actually delivers less output (and hence accrues less opex and capex) than was intended when allowances were set.
- 5.13 Category (a) is the outperformance that the incentive scheme is supposed to promote. Generally, it is seen as a task for the regulator to ensure that targets are appropriately challenging and that companies do not have the opportunity to cut corners on achieving opex and capex, eg by setting defined output targets.
- 5.14 Category (b) can arise because the regulator is tasked with predicting required levels of opex and capex in the future and the cost of these. Therefore it is inevitably uncertain. It also has to predict achievable efficiency improvements. It may have insufficient information available and the regulated company will always have an incentive to overestimate future costs so that it can gain outperformance. The regulator has to make a judgement on the basis of the information available to it and how far it believes it can reasonably challenge the company to achieve targets. There is also a practical difficulty in ensuring that the company then delivers the expected outputs (rather than by under-delivering, see category (c)). This requires close specification of the outputs to be delivered, which is challenging when considering investment in a new network and allowing the company freedom to find the most efficient and effective way of developing that network (see paragraph 5.8(b)).
- 5.15 Outperformance in categories (a) to (c) can come in the form of deferred capex, ie where the company does not or does not need to undertake an investment, or the full extent of the investment, at the expected time or not at all. In this case, PNGL received the capex allowance and it was added to the amount that could be recovered from customers. This gave rise to a financing benefit where capex is delayed or not undertaken because PNGL was also funded for the ongoing financing costs of capex.
- 5.16 UR treated deferred capex in the following way. Where PNGL did not spend its capex allowances, then the underspend was netted off against subsequent capex allowances for the next period, ie if the capex target was £10 million in each period, but in the first period it only spent £5 million, it would receive a capex allowance of just £5 million in the second period. This continues until the original allowance is spent (showing as capex overspend (or under performance)). Customers are not therefore charged for the original capex allowances and the public interest questions over

deferred capex in the TRV therefore refer mainly to the capitalized financing benefits, not the original allowance.

- 5.17 Outperformance as a result of capex deferrals amounts to around half of the total outperformance that went into the 2006 OAV. Issues relating to the treatment of a subset of certain deferred capex projects from 1999/2000 are discussed separately in Section 6 (the 1999/2000 capex deferrals).
- 5.18 There are reasons why it may be desirable and efficient to allow a company to defer capex and earn a return on this. Capital allowances are set in advance. However, flexibility may be required; PNGL, for example, noted that it changed its strategy (see paragraph 2.27). It also told us that the way it rolled out the network was subject to ongoing review and that PNGL responded to where it saw the best potential to attract customers; this necessarily was decided with a short planning horizon, depending on customer surveys, new housing developments and other opportunities. It said that flexibility meant it was most effectively able to attract new customers but meant that the timing of some investments could then be subject to delay. Plans could also be refined and it may be more efficient to delay some investments.
- 5.19 Allowing efficient deferrals means that the regulator can observe that previous capex allowances were not in fact required. Consequently it can modify the process for identifying future capex allowances on the basis of this experience. We are also conscious that if entitlements to recover capex only occur when the money is actually spent, it can increase incentives to stick to original plans in the entirety (so as to earn the full returns) even if more effective or efficient alternatives could have become evident.
- 5.20 We would expect that it would normally be possible for a regulator at the end of a price control period to review whether capex deferrals were efficient (and saved costs or otherwise benefited customers) or whether the deferrals just meant that capex was either not needed or was simply a failure to undertake agreed and necessary investment. However, there was no systematic evaluation by UR of the efficiency of PNGL's capex deferrals capex in this way (see paragraph 5.88).

Historic outperformance

- 5.21 The outperformance elements that were originally included as historic outperformance in the 2006 TRV included opex outperformance, capex outperformance and capex deferrals, WCA outperformance and volume underperformance. The accumulation of outperformance is detailed in Tables 5.1 to 5.3 below. These figures do not include the financing benefit that has arisen on these sums.
- 5.22 Tables 5.1 and 5.2 shows that the largest accumulation of outperformance arose from capex underspend and capex deferrals in 1999/2000. There is also some capex underspend in 1996 to 1998 and 2001, and deferred capex in 2003/04. Opex underspend arises in the period 1999 to 2006. Total outperformance in 2003, 2004 and 2006 is negative. PNGL explained that the majority of the deferred projects from PC01 that were undertaken in PC02 took place between 2002 and 2005. Therefore, although there was underlying capex outperformance in this period, as no further allowances were provided for these deferred projects in PC02, PNGL overspent against its PC02 allowances in this period.

TABLE 5.1 Total capex and opex allowances versus actual spend, 1996 to 2006

£'000, 1996 prices

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
<i>Allowances</i>											
Capex	19,717	15,972	32,978	32,482	38,784	23,307	16,177	11,534	10,554	8,126	8,330
Opex	<u>4,154</u>	<u>6,158</u>	<u>6,980</u>	<u>8,401</u>	<u>9,218</u>	<u>9,075</u>	<u>7,011</u>	<u>6,391</u>	<u>6,396</u>	<u>10,335</u>	<u>10,541</u>
Total	23,871	22,130	39,958	40,883	48,002	32,382	23,187	17,925	16,950	18,461	18,871
<i>Actuals</i>											
Capex	18,248	14,679	31,815	22,461	22,578	21,667	17,610	15,393	13,312	10,847	10,455
Opex	<u>4,221</u>	<u>5,636</u>	<u>7,078</u>	<u>7,235</u>	<u>7,752</u>	<u>7,642</u>	<u>5,369</u>	<u>4,187</u>	<u>4,497</u>	<u>7,486</u>	<u>9,328</u>
Total	22,469	20,316	38,893	29,696	30,330	29,308	22,979	19,580	17,809	18,333	19,783
<i>Difference</i>											
Capex	1,468	1,293	1,162	10,021	16,205	1,640	-1,433	-3,860	-2,758	-2,722	-2,125
Opex	<u>-67</u>	<u>522</u>	<u>-98</u>	<u>1,166</u>	<u>1,466</u>	<u>1,433</u>	<u>1,642</u>	<u>2,205</u>	<u>1,899</u>	<u>2,849</u>	<u>1,213</u>
Total	1,401	1,815	1,064	11,187	17,672	3,073	208	-1,655	-859	127	-913

Source: UR.

5.23 PNGL provided further detail distinguishing deferred capex from 2002, as well as grants,¹³ working capital allowances and volume effects on outperformance, see Table 5.2.

TABLE 5.2 Further details of outperformance 1996 to 2006

£'000

<i>Outperformance calculations</i>	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Deferred capex under(over) spend	0	0	0	0	0	0	-487	3,142	2,566	-2,247	120
Other capex under (over) spend	1,468	1,293	1,162	10,021	16,205	1,640	-946	-7,002	-5,324	-475	-2,245
Grants relative to forecast	-8	121	103	1,127	-454	1,136	770	0	0	0	0
Opex under/(over) spend	-67	522	-98	1,166	1,466	1,433	1,642	2,205	1,899	2,849	1,213
WCA under/(over) spend	-250	1,052	555	-42	143	-127	1,815	548	881	-260	1,289
Volume upside/(downside)	<u>0</u>	<u>0</u>	<u>0</u>	<u>-803</u>	<u>462</u>	<u>2,604</u>	<u>1,912</u>	<u>968</u>	<u>-637</u>	<u>-2,664</u>	<u>-6,257</u>
Total upside	1,143	2,987	1,723	11,469	17,822	6,687	5,193	-3,282	-3,181	-550	-6,001

Source: PNGL statement of case, Annex 10.

5.24 PNGL also provided a breakdown of opex outperformance by year, see Table 5.3. PNGL said that it was not meaningful to provide a year-on-year analysis of out-performance for capex, as annual performance relative to forecast was affected by numerous factors. It said that PNGL re-profiled activities over time, meaning that total out-turn capex outperformance in each year reflected a mixture of unit cost efficiencies and activity re-profiling.

¹³ See paragraph 5.29 for a description of grant outperformance. Grant outperformance did not form part of the outperformance that was included in the 2006 TRV.

TABLE 5.3 Further details of opex outperformance 1996 to 2006

£ million, 1996 prices

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Total
<i>Determined</i>												
Distribution and transmission	0.1	0.7	0.8	1.5	1.6	1.4	1.5	1.6	1.2	1.3	1.3	12.9
Rates	-	0.0	0.1	0.3	0.6	0.9	0.3	0.6	0.9	1.3	1.7	6.9
Manpower	0.9	1.9	2.2	2.9	3.2	3.2	2.4	2.6	2.6	4.0	4.0	29.9
Office costs	0.2	0.6	0.5	0.5	0.6	0.7	0.8	0.8	0.8	1.1	1.1	7.6
Other	<u>3.0</u>	<u>2.9</u>	<u>3.5</u>	<u>3.1</u>	<u>3.3</u>	<u>2.8</u>	<u>1.9</u>	<u>0.9</u>	<u>0.9</u>	<u>2.7</u>	<u>2.4</u>	<u>27.3</u>
Total	4.2	6.2	7.0	8.4	9.2	9.1	7.0	6.4	6.4	10.3	10.5	84.7
<i>Actual</i>												
Distribution and transmission	0.1	0.5	0.5	0.9	0.8	1.1	1.5	1.1	1.5	1.7	2.0	11.6
Rates	0.2	0.2	0.5	(0.6)	0.1	0.2	0.4	0.1	0.1	0.4	0.3	2.0
Manpower	0.7	1.3	1.6	2.1	2.6	2.8	2.0	1.9	2.0	2.7	4.4	24.2
Office costs	0.2	0.3	0.4	0.5	0.6	0.6	0.5	0.4	0.4	0.5	0.5	5.2
Other	<u>3.0</u>	<u>3.2</u>	<u>4.0</u>	<u>4.2</u>	<u>3.6</u>	<u>2.9</u>	<u>0.9</u>	<u>0.7</u>	<u>0.5</u>	<u>2.2</u>	<u>2.1</u>	<u>27.4</u>
Total	4.2	5.6	7.1	7.2	7.8	7.6	5.4	4.2	4.5	7.5	9.3	70.4
<i>Variance</i>												
Distribution and transmission	0.0	(0.2)	(0.3)	(0.6)	(0.8)	(0.3)	0.0	(0.4)	0.3	0.4	0.6	(1.3)
Rates	0.2	0.2	0.4	(0.9)	(0.5)	(0.7)	0.0	(0.5)	(0.8)	(1.0)	(1.5)	(5.0)
Manpower	(0.1)	(0.6)	(0.5)	(0.8)	(0.6)	(0.4)	(0.4)	(0.7)	(0.6)	(1.3)	0.4	(5.7)
Office costs	(0.0)	(0.3)	(0.0)	(0.0)	0.1	(0.1)	(0.3)	(0.3)	(0.3)	(0.5)	(0.5)	(2.4)
Other	<u>0.0</u>	<u>0.4</u>	<u>0.5</u>	<u>1.1</u>	<u>0.3</u>	<u>0.1</u>	<u>(1.0)</u>	<u>(0.2)</u>	<u>(0.4)</u>	<u>(0.5)</u>	<u>(0.2)</u>	<u>0.2</u>
Total	0.1	(0.5)	0.1	(1.2)	(1.5)	(1.4)	(1.6)	(2.2)	(1.9)	(2.9)	(1.2)	(14.2)

Source: PNGL.

Opex and capex outperformance

- 5.25 PNGL said that opex outperformance amounted to 17 per cent of opex allowances over the period between 1996 and 2006.¹⁴ PNGL said that the main drivers for opex outperformance were manpower savings via its partnership with McNicholas,¹⁵ cost savings on market development (manpower and overheads), outperformance on office costs (including rents, utilities, postage, telephones, stationery, IT and finance costs), outperformance on network operations and successful rating valuation negotiations.¹⁶
- 5.26 PNGL said that capex outperformance was 7 per cent of the capex allowances over the 1996 to 2006 period;¹⁷ it said that this outperformance was due to initiatives under its partnership with McNicholas, for example using non-dig rather than open-cut mains laying, pre-assembled meter installation, and a reduction in pay-as-you-go metering costs as well as other general improvements in efficiency.¹⁸
- 5.27 PNGL gave some further explanation of how opex outperformance was achieved. For example, there was outperformance on manpower between 2002 and 2005. At this time, PNGL experienced a heavy loss of staff and replaced them with new staff, who needed training, with a consequent reduction in average salary levels. Meanwhile, PNGL streamlined its operations and consolidated them on one site. It said that management resources were shared between PNGL and McNicholas with no

¹⁴ PNGL [statement of case](#), Annex 6, paragraph 3.

¹⁵ McNicholas has been PNGL's contractor for the roll-out of the gas distribution network, following a successful tender in 1996, and again at re-tenders in 2001 and 2006. PNGL said that there was an 'alliance' partnership between them. There is an open-book cost approach and a profit-sharing mechanism.

¹⁶ PNGL [statement of case](#), Annex 6, paragraph 4.

¹⁷ PNGL [statement of case](#), Annex 6, paragraph 5.

¹⁸ PNGL [statement of case](#), Annex 6, paragraphs 6–8.

duplication or man marking of staff. Control room staff were required to undertake a variety of other processes in quiet periods other than 'core control room activities'. There were increased manpower efficiencies in the sales operations, and market development process and consolidation of marketing and PR agencies. In relation to office costs, PNGL also referred to savings arising from the consolidation at a single out-of-town site including co-location with the contractors' management staff, savings on telephone costs, IT licensing, maintenance and support. PNGL said that these savings were not known when these forecasts were being prepared for the PC02 price control review in October 2000.

Other categories of outperformance

- 5.28 A number of other specific categories of outperformance other than general capex and opex outperformance (and deferred capex) are identified in Table 5.2. These are explained below. Our assessment of the treatment of WCAs and volume effects is set out in paragraphs 5.160 to 5.172.

Grants

- 5.29 PNGL's licence allowed it to retain any difference between the value of grants that it was forecast to receive and the grants that it actually secured. It said that the relevant grants were made by the European Regional Development Fund to the Department of Economic Development for specific energy-related activities, including the development of the natural gas industry in Northern Ireland. The Department subsequently provided some of the grant money to PNGL for its transmission business. PNGL understood that, as with all outperformance under the 1996 licence, it could retain any difference between forecasts and actuals. However, in the 2007 determination, this amount was excluded from the TRV calculations.¹⁹

Working capital allowances

- 5.30 PNGL told us that at the price control reviews, it prepared its forecasts for opex on an accounting basis. It then forecast the level of costs and revenues that were expected to be outstanding at the end of the year to determine the WCAs. If PNGL was able to find more efficient ways of managing its business that allowed it to spend less cash (as opposed to accounting cost) within each control period, it was able to retain the benefit of this outperformance under the original licence. PNGL said that at the time of the 2007 determination, it had accumulated an estimated £9.4 million of WCA outperformance (actualized WCA outperformance was £10.3 million). However, UR only allowed £5 million of this outperformance into the OAV.²⁰

Volume effects

- 5.31 Under the 1996 licence, PNGL's revenues were linked to achieved volumes (ie allowed pricing was set with reference to volume targets rather than revenue targets). Overall, PNGL underperformed relative to its volume targets between 1996 and 2006.²¹ This was largely attributable to volume underperformance in 2005 and 2006. This had the effect of reducing the revenues that PNGL could recover (because its allowances were expressed with reference to a price cap it could charge based on an underlying volume assumption, rather than being allowed a revenue cap to recover

¹⁹ PNGL [response](#), Annex 1, paragraph 2.90.

²⁰ PNGL [statement of case](#), Annex 6, paragraphs 14–17.

²¹ PNGL [statement of case](#), Annex 6, paragraph 10.

its allowances), ie it is recorded as a negative sum, so reducing the aggregate historic outperformance figure.

- 5.32 In the event, no volume upside/downside was recorded from 1996 to 1998 as volumes were reset in 1999 with the actual volumes achieved rather than using the original targets (and hence volume underperformance was reduced). PNGL said that its total cost allowances were also reset at the same time based on actual out-turn activity rather than projections (but unit costs were not reset), ie actual out-turn activity was lower for 1996 to 1998 than the original allowances, and hence recorded outperformance was reduced.

Accumulation of outperformance into the TRV

- 5.33 As noted in paragraph 5.6, PNGL was unable to realize the returns on outperformance as it arose during the period 1996 to 2006 because recovery of allowed revenue was back-end loaded (ie to keep prices over time reasonably stable revenues were deferred until later in the licence period when the number of customers was expected to be higher). PNGL said that this meant that its outperformance was effectively logged up in the licence formulae, to be recovered towards the end of the 20-year recovery period.²² It said that UR agreed as part of the 2006 'agreement' on the package of modifications that the value PNGL would have received under the terms of the original licence should predominantly be included in the TRV in order that it could be recovered in the future through depreciation of the TRV.²³
- 5.34 All opex and capex outperformance, all deferred capex, all volume underperformance and around half of WCA outperformance in the period 1996 to 2006 was capitalized into the asset base (ie the 2006 TRV). UR acknowledged that as part of the 2006 discussions and subsequent 2007 licence modifications, the value of this outperformance was retained and rolled up into the asset base at the prevailing allowed rate of return. This led to an addition of £77.7 million (2006 prices) to the asset base at the end of 2006.²⁴

UR's proposed decision on historic outperformance in PNGL12

- 5.35 In its 2012 determination, UR decided to remove from the asset base a sum equal to the value of the depreciated opex and capex outperformance, WCA outperformance and volume underperformance accumulated between 1996 and 2006 that was included in the 2007 OAV (however, a separate adjustment was made for the 1999/2000 capex deferrals—see Section 6), thus reducing the revenue PNGL can recover in depreciation and return until 2046.
- 5.36 UR said that:
- we decided to make an adjustment to the asset base for the following items in order to deal with historic unspent allowances by PNGL: ...and we have removed from the asset base the residual value of outperformance since PNGL has already benefited from the inclusion of

²² PNGL [statement of case](#), paragraph 3.17.

²³ PNGL [statement of case](#), paragraph 1.27.

²⁴ UR [PNGL12 determination](#), paragraph 7.54.

that outperformance in the asset base for five years and it is appropriate that consumers now benefit from a sharing of its value.²⁵

UR said that if it were to take no action, this would effectively result in PNGL retaining all of the benefit of underspend and deferral of capex, creating a transfer of value of around £74.4 million from customers to shareholders that would earn the full rate of return going forward. UR calculated that this would deliver a cumulative total undiscounted cash flow benefit of around £240 million from the initial underspend of around £42 million.²⁶ It said that it was clearly inappropriate that customers should pay PNGL such an outsize reward, particularly considering that this related to investments that were never made and did not need to be financed. It said that none of the adjustments would leave any stranded assets.²⁷

- 5.37 UR said that it had weighed the best interests of consumers, in terms of the benefit they would receive from a change, against the retention of the relevant sums within the existing TRV. UR said it concluded that, at the present time, it would not be acting compatibly with its statutory duties if it did not seek to modify the TRV.²⁸ UR said that when weighing the effect on consumers if it took no action, against the consequences for PNGL if it did take action, it had concluded that in the circumstances it would not be unfair to PNGL or in any way contrary to its statutory duties to make the proposed amendments to the value of the TRV contained in the current licence.²⁹ It said 'it was our conclusion that the proposed treatment of outperformance and deferred capex was consistent with our statutory duties, and would secure c£74.4 million of benefit for customers'.³⁰
- 5.38 UR said that the benefit that PNGL had accrued between 2007 and 2011 as a result of historical outperformance had taken two forms: (a) a direct and immediate increase in revenues over the period 2007 to 2011 of around £15 million; and (b) because of the profile adjustment, an addition of £20 million to the TRV over the same period, to account for revenues that had been deferred.
- 5.39 UR considered that the £15 million in increased revenues between 2007 and 2011 was an appropriate amount to reward PNGL for outperformance achieved in the period 1996 to 2006. UR said that the £20 million addition remained in the asset base under the PNGL12 determination. The value it represented would be awarded to PNGL over the course of the remaining licence recovery period (ie to 2046), by way of depreciation and the full rate of return. If the licence followed a standard approach with no profile adjustment PNGL would have received around £35 million in revenues over the period 2007 to 2011.³¹
- 5.40 UR said (with regards to outperformance) that its treatment was consistent with best practice, although it was not possible to treat PNGL identically with regulatory best practice given the unique nature of the PNGL regime. UR recognized that not all outperformance was capex in nature. However, it said that its analysis of how other regulatory regimes would have treated savings made, both capex and opex, over the 1996 to 2006 period indicated that the approach it had taken broadly delivered a similar overall sharing of benefits. Furthermore, it was right to treat all the historical

²⁵ UR [initial submission](#), paragraph 1.7. The calculation of the net amount which UR removed from the asset base in 2012 for outperformance is set out in paragraph 7.63 of UR's decision document 2012.

²⁶ UR [initial submission](#), paragraph 1.15. This is UR's analysis of total underspend including deferred capex as well as outperformance. The £42 million sum excludes any capitalised financing.

²⁷ UR [comprehensive response to comments on draft proposal \(2012 decision\)](#), p12.

²⁸ UR [comprehensive response to comments on draft proposal \(2012 decision\)](#), p10.

²⁹ UR [comprehensive response to comments on draft proposal \(2012 decision\)](#), pp10&11.

³⁰ UR [initial submission](#), paragraph 1.22.

³¹ UR [PNGL12 determination](#), p57.

outperformance as capex since the PNGL licence saw all expenditure capitalized, regardless of its nature.³² It said that the price control over the period 2007 to 2011 provided investors with a reward for outperformance (through the profile adjustment). An adjustment to the asset base at the end of the period delivered a sharing of outperformance with consumers, and was consistent with how regulators typically treated capex outperformance.³³

- 5.41 In relation to the 7.5 per cent return on the value of accumulated outperformance, UR noted that there was no actual carry cost of finance for this value, and suggested that this rate of return might be too high a rate to apply to the outperformance-related element of the TRV, but instead something closer to the risk-free rate might be more appropriate. UR said that if a utility without a revenue deferral model wished to earn a return of 7.5 per cent on some of its outperformance revenue—as PNGL would—it would have to reinvest it and put the money at commensurate risk. This was not the case for PNGL.³⁴ However, UR in its PNGL12 determination did not choose to reconsider the appropriate rate of return, but instead acted consistently with the fixed rate of return set under the 2007 determination. We address the appropriate rate of return in Section 7.

PNGL response

- 5.42 In its response to UR's Price Control Draft Proposals 2012–2013 Consultation Paper, PNGL stated that it had

grave concerns that the proposals put forward by UR in its Consultation Paper, in particular UR's stated intention to retrospectively adjust the TRV agreed in 2006 and implemented via modifications to PNGL's licence in 2007, are entirely inconsistent with UR's duties under the Energy (Northern Ireland) Order 2003, and with regulatory best practice. The implementation of such proposals is likely to erode investor confidence and thus increase the cost of capital for both PNGL and other utilities in Northern Ireland, to the ultimate detriment of Northern Ireland consumers.

In its response to UR's Determination Notice, PNGL rejected the Determination Notice and the proposed modification to PNGL's conveyance licence. It stated that the proposal risked causing PNGL, its shareholder, and ultimately consumers significant and unwarranted harm.

- 5.43 The details of PNGL's concerns of UR's decisions are set out below and in Appendix C. We also note that PNGL indicated it believed that UR was misrepresenting outperformance as money that was never spent or invested,³⁵ and the use of undiscounted future values to represent the sums to be paid by customers or received by PNGL was misleading.³⁶ PNGL also argued that UR had mischaracterized the nature of the public interest assessment that was before the CC and that the mere fact that UR had proposed to remove £80.2 million from the TRV did not automatically mean that leaving it in was a detriment to consumers that must be disproved.³⁷ It also said that neither the 2012 determination, nor the original cash flow model, made any

³² *ibid*, paragraph 7.5.

³³ *ibid*, paragraph 7.4.

³⁴ *ibid*, paragraph 7.16.

³⁵ It submitted that rewarding a utility for achieving efficiencies that led to cost savings was a critical part of incentive regulation.

³⁶ While we accept that this was only one of the figures quoted by UR to estimate the cost, it was perhaps inevitable that the 'quarter of a billion pounds' figure was to the fore in public discussions about this price determination. In our view it would be regrettable if statements which could be misleading undermined public confidence in the natural gas industry.

³⁷ PNGL [response](#), paragraphs 2.12–2.16.

distinction between the rate of return to be earned on capitalized outperformance and other functions, and that the allowed rate of return remunerated the overall riskiness of the business.³⁸

Issues relating to outperformance

5.44 We now consider various issues relating to the treatment of outperformance. Our assessment of the question as to whether inclusion of historic outperformance in the TRV is against the public interest, and if so what actions should be taken, is set out in Section 9. Here, we first consider aspects relevant as inputs to the consideration of whether the inclusion of historic outperformance in the TRV is against the public interest (for example, because of manifest errors in the way the rules of outperformance were constructed and applied or in how outperformance was measured) under the following headings:

- (a) was the treatment of past outperformance established;
- (b) treatment of outperformance and consistency with good regulatory practice;
- (c) efficiency of outperformance; and
- (d) funding the same expenditures twice.

5.45 We set out and consider a number of issues raised by the parties in relation to UR's proposals to remove historic outperformance which will be relevant to the discussion of whether its inclusion in the TRV is in the public interest:

- (a) whether there had been previous sharing of outperformance;
- (b) whether exceptional circumstances need to apply; and
- (c) indications prior to the 2011 Consultation Paper that historic outperformance would be revisited.

5.46 Last, we consider issues relating to outperformance in respect of WCA.

5.47 It appears to us that the disagreements between UR and PNGL on the proposed PNGL12 TRV adjustment in relation to outperformance can be grouped under the following headings:

- (a) whether the 2012 TRV adjustment is retrospective and not consistent with best regulatory practice;
- (b) whether the 2012 TRV adjustment is not consistent with expectations;
- (c) whether outperformance was assessed previously;
- (d) whether the 2007 determination was an agreed package that shared outperformance;
- (e) whether exceptional circumstances apply; and
- (f) whether outperformance had been efficiently incurred.

³⁸ PNGL, [statement of case](#), Annex 9, p3.

- 5.48 We set out in Appendix C for each of these issues the statements and evidence presented by PNGL and UR, and we draw on these points in our assessment below.

Assessment of historic outperformance

- 5.49 We first set out whether the way in which outperformance was rewarded was properly set out and understood. Second, we consider whether good regulatory practice indicates that it would be consistent and appropriate to now remove outperformance from the TRV. Third, we look at whether outperformance reflects genuine efficiencies that benefit customers and whether this indicates whether any elements of outperformance should be removed. Finally we address whether there are indications that any elements of expenditure have been inappropriately funded more than once.

Arrangements for the treatment of past outperformance

- 5.50 The arrangements for the treatment of outperformance prior to 2006 (see paragraphs 5.5 and 5.6) are not in dispute. A statement on UR's policy on outperformance can be taken from an Ofreg letter of 20 November 2001 to PNGL setting out its 'minded to' position on the 2001 (PC02) price control. This indicates that there was effectively a 100 per cent retention by PNGL of outperformance, but it also indicates that this was on the basis of realistic cost forecasts by PNGL. In summary the letter said:

- (a) In order to honour the regulatory undertaking given to PNGL it was UR's intention to seek to ensure that actual expenditure equalled allowed/deemed expenditure by thoroughly challenging and minimizing allowed expenditure. However, where PNGL had succeeded in reducing actual expenditure below allowed expenditure in any price control period there was no provision for clawback of that gain in subsequent periods. Thus the allowed/deemed expenditure would be the recognized expenditure for the purpose of calculating PNGL's rate of return.
- (b) UR hoped that this clear statement of regulatory commitment would be accepted by PNGL as being in the interest of establishing a firm long-term basis for price control regulation. In return UR asked of PNGL its cooperation in seeking to minimize allowed/deemed expenditure; and its cooperation in looking at ways in which the interests of both customers and shareholders might be better secured in the future by changes to the regulatory formula.

- 5.51 At the time that the outperformance in question arose, we therefore see that both PNGL and UR understood that the company could expect to retain all the returns to outperformance arising, and there were no indications then applying that these would be time limited or otherwise shared. We note that the PC02 determination included some exceptions to this for deferred capex, which are set out in more detail in paragraph 6.10, but note that PNGL, under the regulatory framework applying in PC01 and PC02, would generally retain the capitalized financing benefits for deferred capex (but unused allowances would normally be offset against future capex allowances).

- 5.52 It was also understood that outperformance that PNGL earned over the period 1996 to 2006 was capitalized into the OAV in 2007 (although UR told us in this investigation that there had been no commitment on its part that it would not later be removed). The approach assumes that revenues received prior to 2006 did not include any reward for outperformance (ie revenues were credited against ongoing actual costs, not credited against repaying outperformance. This convention is significant because inclusion of actual investment and operation costs in the TRV is not controversial.

5.53 We therefore conclude that the treatment of outperformance and the determination of the amount that accrued in the period 1996 to 2006 were understood and that (at least until 2006) the intention was that PNGL would retain the benefits from the outperformance so calculated.

Good regulatory practice

5.54 UR said that in its view historic outperformance should not continue to be included in the TRV because to do so would not be consistent with good regulatory practice. We consider two aspects of this: whether UR's proposed sharing of outperformance is consistent with good regulation; and second whether the application of principles of good regulation can also be applied within the context of PNGL's historical outperformance.

5.55 UR said that the April 2007 consultation paper showed the importance it put on sharing of outperformance based on regulatory practice elsewhere. It said in order that the benefits from PNGL's outperformance were shared between the company and customers, it was necessary to remove the historical outperformance from the asset base at the end of the five-year period 2007 to 2011.³⁹ This adjustment to the asset base has the effect of limiting PNGL's returns on outperformance to five years. This, it indicated, represented a fair sharing of past outperformance between the company and consumers.

5.56 UR said that its proposals on outperformance were consistent with regulatory best practice, although it noted that it was not possible to treat PNGL identically with regulatory best practice given the unique nature of the PNGL regime (see Appendix C, paragraphs 17 to 24),⁴⁰ for example there were no similar cases of outperformance forming a large proportion of the opening asset base in the privatizations in Great Britain. It said that to compare it with other regimes it was useful to think of the PNGL outperformance as all being achieved at the start of 2007, and the first opportunity to remove it from the asset base (in line with standard regulatory practice) was in PNGL12 after PNGL had earned five years' reward on the historical outperformance.

5.57 UR provided two specific examples of regulatory decisions where outperformance was split between company and consumers or the reward for outperformance was time limited (see Appendix C, paragraph 22). It said

Ofgem's approach to capex outperformance has in the past been to let allowed expenditure remain in the asset base for a period of five years, during which time the company enjoys the depreciation and return on unspent capex. However, after the five years have passed, actual expenditure replaces allowed expenditure in the asset base, which ensures that consumers also share in the benefits.⁴¹

UR also said that in Ofwat's most recent price control, capex outperformance was shared between the company and customers on a 30/70 basis (on average).⁴²

5.58 UR also referred to a number of other examples of sharing of outperformance (see Appendix C, paragraph 24), including actions by Ofgem, the Office of Rail Regulation (ORR) and the Civil Aviation Authority (CAA).

³⁹ UR [supplementary submission](#), paragraphs 7.56 & 7.59.

⁴⁰ UR [supplementary submission](#), paragraph 7.4.

⁴¹ UR [initial submission](#), paragraph 3.19.

⁴² UR [PNGL12 determination](#), paragraph 7.60.

- 5.59 PNGL indicated that it had not disagreed that UR could judge it appropriate to move to a system that shared outperformance, although as noted in paragraph 5.8 it had thought that a high degree of outperformance incentive had been appropriate and noted that the pre-2006 system was also fairly common regulatory practice (see Appendix C, paragraph 11). Instead, its objections related to its view that the changes UR had proposed were retrospective, and because no prior indication was given that changes could be made. PNGL viewed the changes as retrospective in that they affected how outperformance was rewarded after that outperformance had been achieved. PNGL said that the outperformance sharing systems applying up to 2006 had been clearly established, and the changes were at odds with appropriate ex ante regulation, where companies could understand and anticipate the regulation they would be subject to (see Appendix C, paragraphs 3 to 5 and 8).
- 5.60 PNGL considered that UR had used its stated precedents selectively, and these did not reflect the circumstances which applied in this case (see Appendix C, paragraph 13).⁴³ PNGL said that these precedents cited by UR showed an aversion to any retrospective adjustments of the TRV. Such adjustments had only been made in exceptional circumstances, none of which applied in PNGL's case.⁴⁴
- 5.61 PNGL stated that in contrast to the examples of best practice given, UR's actions were not ex ante (see Appendix C, paragraphs 13 and 14). It said that the cited Great Britain mechanisms allowed the previously agreed OAV to be updated to reflect capex since the last review, they were not examples of regulators revisiting the OAV agreed at the start of the previous control period.⁴⁵ PNGL said that other regulators had indicated that there should be no retrospective action and no change in the treatment of assets already in the asset base, in order to provide certainty for investors.
- 5.62 UR referred to Transco (1997)⁴⁶ as a case where an OAV had been revised (see paragraph 5.70). It said that this MMC decision supported making UR's suggested adjustment to the TRV.
- 5.63 However, PNGL said that this case provided was an example of a situation where an inconsistency was identified in the methodology used to calculate depreciation in two different elements of allowed revenue. The MMC's solution to this identified concern was not to reopen the asset value that had been set in 1993, but instead to ensure that the methodologies used going forward were consistent. Indeed, the MMC emphasized the undesirability of reopening previous regulatory price controls.
- 5.64 UR did not accept that its actions were retrospective. It stated that it regarded its proposals as entirely prospective in nature as they did not claw back any value that PNGL had received from outperformance during the last five years, but instead were directed towards addressing the question whether TRV should continue to include historic outperformance from this point onwards (see Appendix C, paragraph 17).⁴⁷
- 5.65 UR acknowledged that it had not been totally clear in 2007 as to its intentions on the future treatment of outperformance but it had made no commitment that outperformance would not be revisited and had indicated that sharing of outperformance was in its mind (see Appendix C, paragraphs 39 to 41). Moreover, it had a clear duty to

⁴³ PNGL [statement of case](#), paragraph 1.49.

⁴⁴ PNGL [response](#), paragraph 1.7c.

⁴⁵ PNGL [statement of case](#), paragraph 4.39.

⁴⁶ MMC (1997) *BG Plc: A report under the Gas Act 1986 on the restrictions of prices for gas transportation and storage services*.

⁴⁷ UR [supplementary submission](#), paragraphs 2.54–2.56.

balance its objectives in accordance with the public interest and so in any event it had to make an appropriate decision on these issues.

Assessment

- 5.66 There are many examples of regulators sharing outperformance as it arises between companies and customers. Taking account of the balance of its objectives, it seems reasonable that UR could determine that sharing of outperformance is appropriate, so as to benefit customers while still providing PNGL with incentives to seek efficient outperformance. We note that PNGL has not objected to this principle. Since PC03 a rolling five-year incentive mechanism allows PNGL to retain parts of the benefits of future capex outperformance (or carry parts of the consequences of capex overspend, see paragraph 5.9).
- 5.67 However, the situation differs where actions are not purely prospective in nature. We do not agree with UR that the impact of the removal of historic outperformance from the TRV is just prospective. While, as UR states, this would not claw back returns on (and returns of) outperformance which have already been earned, the incentives which will be realized for the achievement of efficiencies and outperformance applied during the periods between 1996 and 2006 will turn out to be different to the ones which were understood to apply at the time when they were earned, and when these had been rolled up into the TRV. This difference could be significant; for example, consider opex outperformance—normally this would be retained by the regulated company as it arose each year, but because of the revenue deferrals, PNGL has only recovered through the depreciation of the TRV a proportion of this reward (in this case depreciation is over a 40-year period and PNGL has only received depreciation for five years). Similarly for capex outperformance the return and depreciation achieved to date would be below those expected at the time when PNGL generated this outperformance. Therefore removal of historic outperformance, whilst not clawing back the returns on outperformance that have already been earned, would mean that a proportion of the outperformance itself and the returns earned on it, which PNGL would have expected to receive at the time, would not now be received.
- 5.68 We consider that good regulatory practice could allow for the treatment of outperformance which involves sharing with customers and time limits on the returns that could be earned on outperformance. However, we have not found any evidence that regulatory practice supports changes to the amount of outperformance that a regulated company can earn after the outperformance has been generated. The reasons for this are referred to in Section 8. While the situation in PNGL's case is unusual because of the historic outperformance accumulated because of the deferral of revenues and the transition to a RAB-based regulatory system, we do not see that good regulatory practice of itself includes the adoption of measures with an ex post impact on the amount of outperformance included in the TRV, as it is not consistent with good practice of ex ante incentive regulation.
- 5.69 Moreover, we consider that allowing PNGL to recover outperformance now that it could not recover at the time when it was earned remains consistent with the returns that were originally intended and agreed for the developer of the network as part of the heightened incentive system that was applied (see paragraphs 9.103 and 9.104). The risks faced by PNGL were different from those faced by a company in a mature utilities business. That a company involved in a greenfield development is provided with rewards and incentives that differ from those in the regulation of mature utilities is a necessary recognition of the risks it has accepted in undertaking to develop the industry.

5.70 We do not agree that the CC/MMC Transco decision in 1997 provides support for UR's proposed treatment. UR said that the MMC found that Transco's licence conditions operated against the public interest by producing a level of revenue for the company which was a great deal higher than that necessary to finance the carrying on of its activities, contrary to the interests of consumers as regards prices. It said that the MMC determined that a RAB of £11.6 billion should be adopted compared with the true replacement cost of £17 billion in Transco's books. It said that the MMC did not seem to believe that the effect of this £5.4 billion reduction would lead to investor uncertainty which would ultimately harm the public interest.⁴⁸ However, in our view this decision was not related to how much outperformance the regulated entity was entitled to retain (but related to the calculation of depreciation charges on the TRV applied from 1991 to 1997). This is set out in paragraph 1.6 of the MMC decision.⁴⁹ To summarize, BG's WACC was applied to a capital value based on its 1991 market value whereas depreciation was allowed on the full (higher) market value of its assets. This created an inconsistency, which the MMC in 1997 corrected so that in the future depreciation would just be applied to the lower figure. Extra depreciation earned since 1993 was not clawed back.

5.71 Furthermore we note that the report sets out that it is generally not appropriate to claw back revenue allowed in previous price control periods where the regulator makes a decision to change future arrangements; paragraph 2.141 of the report reads:

We consider that it is normally undesirable for previous regulatory price controls to be reopened. The RPI-X and periodic price control system does carry risks that allowed revenue may result, in some price control periods, in prices to customers which are either higher or lower than subsequently appear justified. It is right for regulators to seek to capture for customers some of the benefits of efficiency gains. It can also be appropriate to recover excess revenues for allowed capital investment which did not take place. However, we believe it is generally inappropriate to seek to claw back revenue allowed in a previous price control period, where a regulator has decided to change for the future the basis on which such revenue should be calculated, as would be the case in respect of this depreciation allowance.

5.72 Nonetheless, we recognize that a regulator is required to make decisions in line with its statutory objectives. In doing so, it cannot be bound completely either by regulatory precedent and best practice, or its own prior decisions, if these will result in outcomes which are at odds with an appropriate balance of its statutory objectives. While adherence to prior decisions and clear practice is an important aspect of regulation, it cannot of itself completely override a need to reach appropriate overall determinations. In Section 9, we consider whether the inclusion of outperformance items in the TRV is against the overall public interest, in the context of other relevant issues such as the consumer interest.

⁴⁸ UR, [Legal submission in response to provisional determination](#), paragraphs 2.163–2.165.

⁴⁹ Paragraph 1.6 reads:

In the 1993 MMC report, in considering the cost of capital and the asset base to which it should be applied, the MMC took into account the ratio of the 1991 market value of BG's shares to the balance sheet value of its assets, referred to as the market to asset ratio (or MAR), and apportioned equally across BG's businesses. We believe that approach to the valuation of assets at December 1991 remains appropriate. Given that discount on book value, we accept the Director General's arguments that to allow full depreciation in revenues during the period under review may be expected to result in prices higher than necessary to finance the carrying on of Transco's activities, to the detriment of consumers of gas. We have concluded that for the period under review only MAR-adjusted depreciation should be allowed on pre-1992 assets and full depreciation on subsequent investment ...

Efficiency of outperformance

5.73 As outlined in paragraph 5.12, outperformance can arise in several different ways. The retention of outperformance by regulated companies is intended to incentivize efficiencies (see paragraph 5.12 (a)). There is therefore a question whether recorded outperformance actually reflect efficiencies that benefit customers or some other cause (see paragraph 5.12(b) and (c)). Regulators generally set out the rules under which the regulated company can retain outperformance as part of the charge control determination. At the end of the charge control period the regulator then reviews what proportion of outperformance the regulated company can retain applying these conditions. There was no specific provision for the treatment of inefficient outperformance in the 1996 PNGL licence and neither did the 1996 licence envisage that outperformance would be subject to an efficiency test. Instead, the 1996 licence secured that PNGL would be permitted to set charges so that over the whole 20-year licence term it would recover its forecast capital and operating costs in present value terms, ie it would be able to retain the difference between the allowed and out-turn costs for any given regulatory control period.

5.74 In its PNGL12 determination, UR stated in relation to outperformance:

having reviewed our files from the 2006/7 period, there are a number of things that are clear. Namely that:

- A sum in respect of deferred capex and historical outperformance entered the asset base in 2006;
- In deriving this sum, no assessment was made as to whether this represented genuine efficiencies; and
- This sum did not include sharing with customers based on regulatory practice elsewhere.⁵⁰

5.75 PNGL said that the question of efficiency was not relevant for our deliberations because: first, the 1996 licence allowed PNGL to keep the benefit of all outperformance without reference to any efficiency assessment (and to perform an efficiency test now would therefore undermine incentive regulation); second, reassessment of PNGL's outperformance efficiency many years ago was not possible; and third, there would be grave doubts as to whether any current assessment could be more reliable than decisions taken at the time of the past price controls. It said that therefore reassessment would only be appropriate if new facts emerged or there had been an error (see Appendix C, paragraphs 119 to 121).

5.76 UR said that there had been no assessment of whether outperformance had been efficiently incurred when it proposed its reduction in the TRV. It said that because its intention was to adjust the TRV to remove historic outperformance, it did not consider in its determination whether the sums attributed to outperformance represented a valid reward to PNGL for efficiencies. It said that the lack of detailed information made it difficult to establish with certainty how much outperformance was efficient.

5.77 PNGL pointed out that in 2006 UR said:

A proportion of outperformance on costs should only be retained by shareholders where the outperformance can be clearly demonstrated to

⁵⁰ UR PNGL12 determination, paragraph 7.7.

have benefited customers, or will benefit customers in the future. All outperformance data for the period 1996-2006 will be rigorously interrogated to this end. Ofreg's⁵¹ primary duty requires that this approach is taken.⁵²

- 5.78 PNGL said that this statement was inconsistent with UR's assertion that there was no assessment as to whether the outperformance represented genuine efficiency. It said that after several price control reviews which in each case entailed at least 12 months of detailed discussions, in which UR instructed technical consultants, sent multiple information requests and held meetings with PNGL, and given that UR had publicly stated that it would only allow PNGL the benefit of efficient savings, it considered that UR's claim was simply extraordinary⁵³ (see also Appendix C, paragraphs 114 to 116). It noted that the treatment of outperformance was subsequently agreed.⁵⁴ PNGL indicated that it believed that UR must have been satisfied over the efficiency of the achieved outperformance at the time.
- 5.79 However, UR stated that the paper quoted referred to an intention to undertake a review of the efficiency of investments. It said the fact that no review took place and that all of the historical outperformance was treated as efficient was clearly a favourable outcome for PNGL.⁵⁵
- 5.80 UR said it thought that past outperformance might not in fact have been efficient, and particularly said that the sums relating to outperformance in 1996 to 2000 represented something other than efficient outperformance against appropriate ex ante targets. It drew attention to two particular issues:
- The first relates to outperformance achieved in 1996 to 1999. The first price control was put in place in September 1999. UR noted that PNGL resubmitted its figures in 1999, and it said it would then seem reasonable to assume that neither any outperformance nor any underperformance could occur in the period 1996 to 1999. UR noted that PNGL's licence created an obligation on it to provide best estimates. However, it found that there was a significant element of outperformance attributable to this period (see Appendix C, paragraph 130 to 136).⁵⁶ (We note that this includes part of the WCA outperformance). UR told us that this period accounted for £36 million of the amount attributed to outperformance. UR said that the calculation of outperformance at this time was based on a regulatory determination that were not set until 1999, based on information provided in 1999, ie these were ex post forecasts, and UR said that they should therefore have been based on actual out-turn costs and therefore to have allowed no room for outperformance.
 - Second, UR said that the figure for outperformance included some value for deferred capex. It said that only large and easily identifiable projects were included in its assessment of deferred capex for the purposes of PNGL12 (ie the 1999/2000 capex deferrals), and there might very well be deferred amounts within the outperformance figure for other types of capex (eg feeder and infill mains laying).⁵⁷

⁵¹ UR was then known as Ofreg.

⁵² Paragraphs 4.2 & 4.3, Phoenix Refinancing Opening Asset Value, Ofreg position, Note, 3 August 2006., see (PNGL [statement of case](#), paragraph 5.16).

⁵³ PNGL [response](#), paragraph 1.7.

⁵⁴ PNGL [statement of case](#), paragraph 5.17.

⁵⁵ UR [supplementary submission](#), paragraph 2.96.

⁵⁶ UR [supplementary submission](#), paragraph 2.99.

⁵⁷ UR [supplementary submission](#), paragraph 2.102.

- 5.81 In response, PNGL stated that the figures for 1996 to 1999 costs were UR's determination of allowances for 1996 to 1999, not actualized values. Actualized cost data was not finalized until PNGL's Regulatory Accounts were subsequently prepared, taking account of UR's determination. It said that the information it submitted in 1999 to UR was based on its accelerated network build programme (see paragraph 2.27) for activity levels from 1999 (and actuals before then), but it was based on a unit cost allowance based on 1997 costs (rather than actual costs).
- 5.82 PNGL said that the agreement between the Department of Economic Development and PNGL in September 1996 provided the incentive regime that was to apply to outperformance from the date of grant of the licence in September 1996. It said that the 1996 licence (in common with energy and water licences in Great Britain) did not identify the 'reference point' (ie determined cost allowances) against which PNGL's actual capex and opex performance should be assessed. This reference point was for UR to determine, although, in the event, UR delayed formally documenting the reference point until September 1999. PNGL said the manner in which that reference point was to be calculated was understood from the outset and was confirmed formally in UR's first price control (PC01) determination. It said therefore it was entitled to outperformance under its original licence.
- 5.83 PNGL said that the reference costs for 1996 to 1998 in the PC01 determination for capex were target costs derived from the contract payments to McNicholas during the period 1996 to 1998 (ie the tendered rates), and the actual level of activity rather than the forecast level of activity. It said that the McNicholas rates were a suitable benchmark as they came from the original European tender process. PNGL said that from this it was clear that UR set the PC01 allowances to mimic how it might have set the allowances had it had the opportunity to do so in 1996. An efficiency factor was also applied. PNGL said that the target cost level against which outperformance was measured therefore had a clear and objective basis (see Appendix C, paragraph 108). However, UR said that its review of documents from the time showed it was not credible that the regulator would have decided to mimic what would have been done in 1996 as suggested by PNGL. It suggested that the regulator at that time really struggled to try to understand what was going on with the information it was provided with and consequently gave allowances that it thought were based on actuals.
- 5.84 PNGL referred to UR's consultants' reports, for example from W S Atkins in May 1999 and Pannell Kerr Forster Corporate Finance, which both looked at project information and actual results in 1996 to 1998 (see paragraph 5.78). Therefore it indicated that UR would have been aware at the time that it was accumulating outperformance. PNGL also said that the value of outperformance agreed in 2006/07 was subjected to a full audit by UR's advisers, Ernst & Young.⁵⁸ It also said that with the numerous reviews, information exchanges and meetings over a number of years, it defied credibility for UR to argue that it had not reviewed the efficiency of historic outperformance achieved between 6 and 16 years ago. PNGL said that in the absence of any new information it was not appropriate retrospectively to reopen tests and measurements of the outperformance achieved between 1996 and 1998, see Appendix C, paragraphs 108 to 110.
- 5.85 While outperformance is recorded for 1996 to 1998, we note that at this time PNGL significantly underperformed on its volume targets. However, in 1999 UR used actual volumes for the period 1996 to 1998 in the PC01 determination (and through this PNGL was able to avoid significant losses under the volume incentive mechanism). UR told us that this had a large effect; it said if it had used the 1997 forecast rather

⁵⁸ PNGL [response](#), Annex 1.

than actual, PNGL would have lost around £23 million in revenue. PNGL said that using the lower volumes of actual assets built rather than forecast volumes of assets built in calculating target allowances meant that recorded outperformance was reduced.

5.86 We note that a large part of outperformance was recorded in 1999/2000, just after the first price control. Immediately after a price review we would not normally expect such significant outperformance, as actual activities and their costings should correspond closely to what was in the agreed plans. This period coincided with PNGL's change of strategy which included the acceleration of capex, but the outperformance figures suggest that either large parts of capex were deferred or not undertaken, or that substantial, unforecast savings were quickly achieved. PNGL said that the 1999/2000 outperformance was made up of three main categories (see Appendix C, paragraph 112):

- continued improvements in costs against tender rates;
- deferrals, eg from changing projects as PNGL identified and responded to customer demand; and
- renegotiation of the tender rates in the McNicholas contract, which delivered unit cost reductions. PNGL said that this occurred in November 1999 and because of the increased volumes of work from the accelerated build programme, the renegotiation yielded £3–£4 million of outperformance in that year. PNGL also said that there was some retrospection in the negotiated rates so the savings reflected some historical activity.

5.87 PNGL also noted that it had been required to deliver against a pre-agreed set of output measures (see paragraph 5.8(b)) and therefore it was not able to achieve outperformance through under-delivery or allowing standards to fall through under-investment.

5.88 UR explained that it had not pressed further on whether past outperformance over the period 1996 to 2006 was efficient. It said:

we have noted that the history of PNGL has many unique features. In making our decisions we have had to deal with historic issues from the original failed business model in a way that seeks to draw a line under the past in order to facilitate the move to the new RAB model based on more normal regulatory practice. In doing so, with a view to delivering the benefits to be obtained from that transition, we have had to strike a balance between different considerations and have sometimes decided not to revisit issues that, in other circumstances, would certainly have merited greater scrutiny.

It said:

For the avoidance of doubt we have never reviewed outperformance for efficiency and have not done so in making our PNGL12 proposals. We have treated the whole amount as if it was normal efficient outperformance earned against ex-ante forecasts ... We decided not to carry out a review when setting the OAV in 2007. At that time we were aware of the extent of the deferred capex issue and determined to review it in 2007. By its nature, the issues within an outperformance efficiency review would be more diverse and complex and we have determined not to proceed with one. ...in dealing with all the unique

features of PNGL's history and in moving to a new licence regime as a result of the failure of the old one, we have had to make decisions in drawing a line under the past and achieving a balanced approach in our decisions.

However, we note that UR did review some capex deferrals and accepted them as efficient, see paragraph 5.98(c).

Assessment

- 5.89 The intention of rewarding outperformance is to encourage the achievement of efficiencies. Therefore outperformance should be an accurate reflection of cost savings that were efficiently incurred, rather than where, for example, the regulated company provides deliberately misleading information to the regulator or where the regulator made a technical error⁵⁹ (eg a calculation error). In such cases we would not expect any reward to be made for outperformance. We first consider whether there are any reasons such as technical errors which mean that recorded outperformance might have arisen for these reasons rather than reflecting actual efficiencies.
- 5.90 In Section 9 we consider whether the inclusion of PNGL's outperformance in the TRV would be against the public interest.
- 5.91 Neither the 1996 licence nor UR's regulatory framework applying in 1996 to 2006 envisaged an efficiency test for outperformance and PNGL and UR may therefore not have collected the relevant information which would be required to fully assess efficiencies (see Appendix C, paragraph 117). Apart from an efficiency test for some capex deferrals (see Appendix D, paragraph 162 to 164) we have not seen any evidence that UR had undertaken any assessment of the efficiency of outperformance that occurred in the period 1996 to 2006 either in its PC01, PC02 or PC03 determinations or at the time of the 2006 'agreement' on the package of modifications. We considered whether it would be possible for us to revisit the elements of PNGL's outperformance (for example, on capex deferrals or unit cost outperformance) and undertake our own efficiency assessment. We concluded that this was impractical—the information necessary to undertake such an assessment was simply never collected and prepared at the time. We could not now identify the exact circumstances under which each element of outperformance had arisen, and whether this was efficiently incurred (eg whether expenditures were less than the allowance because a lower cost had been achieved, because a way had been found to achieve the same effect with fewer inputs, or because fewer inputs were used but this impeded the delivery of outputs, as that information was not recorded at the time and could not be reconstructed up to 16 years after the event). Nor have we been able to identify information that would enable us to assess whether or to what extent the pricing benchmarks used from 1996 to 1999 were inappropriate, such as, for example, an assessment of rates in Northern Ireland compared with elsewhere in Great Britain.⁶⁰ We therefore think that it is not possible now to fully assess all elements of PNGL's historic outperformance and determine which proportion was or was not efficiently earned.
- 5.92 We thought that technical errors in UR's treatment of outperformance in the period 1996 to 2006 could impact on the assessment of whether outperformance included in the TRV was in the public interest. Therefore we assessed if UR's reasoning in

⁵⁹ By technical errors we mean, for example, the input of incorrect data or an erroneous mathematical calculation, which are clearly wrong. It does not refer to differences of opinion on judgement and discretion.

⁶⁰ Although such a comparison would not necessarily be informative anyway, if the circumstances differed between Northern Ireland and Great Britain, for example because a natural gas distribution industry already existed in Great Britain.

relation to outperformance disclosed any specific errors in relation to the efficiency of outperformance. UR's and PNGL's submissions highlighted the following potential technical errors:

- (a) no efficiency test was performed for opex and capex outperformance;
- (b) outperformance in the period 1996 to 1998 was wrongly included in the PC01 determination;
- (c) a large amount of capex outperformance was due to deferral of expenditure; and
- (d) PNGL was funded twice for certain business rate expenses.

(a) no efficiency test was performed for opex and capex outperformance;

- 5.93 We do not think that the absence of an efficiency test by UR in its past regulatory decisions discloses a technical error. The 1996 licence did not foresee an efficiency test. No assessment of the efficiency of outperformance was foreseen ex-ante and no criteria were set ex ante for such an assessment of outperformance. We also note that UR had the opportunity to perform such an efficiency test in its PC02 and PC03 determinations (or at the time of the 2006 'agreement') or could have signalled that it would perform such an assessment in the future (as it did for the 1999/2000 capex deferrals), but chose not to do so.

(b) outperformance in the period 1996 to 1998 was wrongly included in the PC01 determination

- 5.94 In regard to the outperformance achieved in the period 1996 to 1998, we consider that the licence provided for PNGL to earn outperformance from 1996. We do not think that the fact that UR did not set the reference costs until 1999 does of itself mean that it therefore cannot benefit from prior outperformance. UR said that PNGL's 1999 submission was misleading, because it was not based on best estimates as it contained forecast costs when actual costs were available. We find PNGL's account that UR must have known at the time it made its PC01 determination that it was allowing PNGL to retain past unit cost outperformance (which is referred to in the consultant reports on capex that UR commissioned at the time) plausible, and we cannot therefore conclude that the use of reference costs different to actual costs (if these had been known) was a technical error. The evidence from the consultants' reports does suggest that UR was aware that outperformance was being accumulated, and it seems very unlikely that it would have believed at the time that the reference costs derived from PNGL's information were PNGL's actual costs. UR did not challenge this at the time. However, we believe that UR must have known at the time it made its PC01 determination that it was allowing PNGL to retain past unit cost outperformance.

- 5.95 It also seems favourable to PNGL for McNicholas' tender rates to be used as a reference, and for PNGL then to be rewarded for negotiating lower actual rates, yielding outperformance which could in part end up being shared between PNGL and McNicholas (PNGL told us there was a profit-sharing mechanism with McNicholas). Given that there was no established natural gas industry in Northern Ireland at that time, we cannot be certain that the rates determined by competitive tender were at fully efficient levels. We also thought that it was surprising that UR allowed these higher unit cost assumptions in the PC01 determination without making any reference to this fact in the PC01 determination and without any explanation as to why it

was appropriate at that time to reward PNGL with such a benefit, considering that consumers would have to pay for this and given UR's duties to consumers.

5.96 We note the use of actual gas volumes for 1996 to 1998 in the PC01 determination when PNGL would have significantly underperformed its volume targets set out in PNGL's 1997 submission. This meant that PNGL was able to avoid significant payments under the volume incentive mechanism. Whilst the allowed volumes of capex were also reduced to equal actual capex volumes (but not the unit costs), this did nevertheless mean that PNGL received a significant concession at this time. In conjunction with the use of forecast (rather than actual) unit costs, and basing these reference costs on McNicholas' tender rates, this does suggest that in PC01 PNGL benefited from that particular approach.

(c) a large amount of capex outperformance was due to deferral of expenditure

5.97 A large part of the outperformance that was achieved in the period 1996 to 2006, as detailed in Tables 5.1 and 5.2, came from deferred capex other than the 1999/2000 capex deferrals (see Section 6 for our assessment of the 1999/2000 capex deferrals).

5.98 The outperformance in the 2006 TRV attributable to capex deferrals (other than the 1999/2000 capex deferrals) included:⁶¹

(a) capitalized financing for projects that were deferred within the period 1996 to 2006 (but not beyond);

(b) the original allowance for capex deferrals for feeder and infill capex that were deferred into PC03 (including the associated capitalized financing). These allowances were subsequently deducted from the capex allowances in PC03;⁶² and

(c) the original allowance including capitalized financing for capex deferrals which UR did consider represented efficiency savings and should therefore be retained by PNGL (following an efficiency analysis performed by UR).⁶³

5.99 The inclusion of these in the 2006 TRV was deliberate. We note in particular that:

(a) UR included the capitalized financing for capex deferrals within the period 1996 to 2006 in the 2006 TRV, but did not signal any further adjustments;

(b) UR, in its PC03 determination, deducted any remaining capex deferrals for feeder and infill assets from the capex allowances in PC03, but did not signal any further adjustments and it is our understanding that the associated projects have now been completed; and

(c) UR said that it allowed PNGL to retain 133 km of infill mains and 30 km of feeder mains capex in the 2006 TRV (including the associated capitalized financing) following an efficiency assessment.

5.100 We have not found that any other decision in relation to the past treatment of outperformance has been technically wrong. We conclude that UR chose not to undertake

⁶¹ See, Appendix D, paragraphs 154–172 for details on capex deferrals other than the 1999/2000 capex deferrals.

⁶² See Appendix D, paragraphs 158, 159 & 167.

⁶³ See Appendix D, paragraphs 163 & 164.

efficiency assessments at the time but had relevant evidence at its disposal including consultants' reports (which could have alerted it to possible issues developing).

(d) Funding the same expenditure twice

- 5.101 We note that PNGL outperformed on business rates over the period 1996 to 2006, in part because the allowances on business rates in UR's determinations were linked to allowed revenues, but actual revenues were deferred to later years because of PNGL's under-recoveries of revenues as a result of PNGL pricing below its price cap. However, we observe that under the regulatory framework applying from 2007 onwards, PNGL will be entitled to recover the full amount of business rates in the future when it receives the deferred revenues associated with the previous under-recovered revenues (see Appendix C, paragraph 133 to 136). This means that from 2007 onwards PNGL receives an allowance for business rates based on actual revenues (which will include the revenue under-recoveries that have been deferred from the period 1996 to 2006 into later periods), even though PNGL has already been funded for the business rates relating to the revenue under-recoveries. There is therefore a risk that PNGL will be funded twice for the same expenditure.
- 5.102 UR told us that there might be possible double counting of allowances in opex and the management fee, and unused allowances in respect of the acquisition of the old towns gas network (see Appendix C, paragraphs 155). However, PNGL disagreed with this suggestion. UR did not provide supporting evidence to substantiate this claim and we have therefore not considered it further.
- 5.103 With regard to the risk that PNGL is funded twice for the same business rate expense, whilst we accept that PNGL's under-recovered revenues in the 2007 determination were subject to a penal interest rate (which had the effect that PNGL did not retain the full economic value⁶⁴ of the under-recovered revenues), it will nevertheless receive funding twice for the business rates relating to the revenues that it does recover (first in the period 1996 to 2006 and then again for the same revenues as and when they occur in the future). We think that funding PNGL twice for the same expense is a technical error and that this would operate against the public interest.
- 5.104 In our provisional determination we made an adjustment to the TRV for business rates outperformance that was the result of PNGL's revenue under-recoveries of £5.3 million. We calculated this adjustment on the basis of PNGL's submission that 60 per cent of the outperformance on business rates in PC02 might be related to revenue under-recoveries. We did not calculate an adjustment for PC01.
- 5.105 PNGL later (in response to our provisional determination and in response to follow-up questions by us) provided more detailed calculations and explanations that implied that the adjustment for PC02 should be reduced to around 30 per cent of business rates outperformance as:
- (a) parts of the business rates outperformance related to the transmission business;⁶⁵

⁶⁴ The full economic value of revenue under-recoveries is the amount PNGL would have recovered without the application of the penal interest rate, ie if the revenue under-recoveries were capitalized at PNGL's rate of return rather than at the penal interest rate.

⁶⁵ See Appendix C, paragraph 94.

- (b) PNGL's business rates allowance in PC02 was set on the basis of revenue estimates (rather than allowed revenues) that were lower than the revenues allowed in UR's PC02 determination;⁶⁶
- (c) parts of the business rates outperformance was due to the negotiation of better business rates with the VLA;⁶⁷ and
- (d) revenue under-recoveries occurred mainly towards the end of PC02 (which results in a lower capitalized financing adjustment).⁶⁸
- 5.106 In addition we think that PNGL's calculations did not fully take into account that revenue under-recoveries were subject to a penal rate of return (over the period 1996 to 2016), which would have the effect of further reducing PNGL's revised estimate of 30 per cent for PC02.⁶⁹
- 5.107 However, it appears that PNGL's calculations did not take into account the effect of volume underperformance; volume underperformance would further reduce the amount of business rates outperformance that is associated with revenue under-recoveries. This is because there is no risk of PNGL being funded twice for business rates associated with volume underperformance because PNGL cannot recover revenues lost in the period 1996 to 2006 due to volume underperformance.^{70,71}
- 5.108 UR said that there were significant revenue under-recoveries in PC01 and that the scale of under-recovered revenues over the course of PC01 was greater as a proportion of revenues compared with PC02 (63 per cent for PC01 compared with 44 per cent over PC02).⁷² This indicates a risk that consumers are paying twice for business rates related to revenue under-recoveries originating in PC01 and so an adjustment to business rates outperformance in PC01 may also be appropriate.
- 5.109 PNGL said that it would be too difficult to calculate the appropriate adjustment for PC01 because it was not clear how the business rates allowance in PC01 was calculated and this meant that it was not possible to say what percentage of business rates outperformance in PC01 was due to revenue under-recoveries. PNGL also said that some of the business rates outperformance in PC01 was due to its successful negotiations with the VLA.
- 5.110 However, PNGL did say that it understood that the business rates allowance for PC01 was determined on the basis of expected revenues.⁷³ The 1999 PKF report⁷⁴ (which the UR relied on in setting the PC01 opex allowance) explicitly refers to an agreement of the VLA with PNGL: 'The VLA has now determined how rates should be levied on PNG's pipeline system. In effect the rates will be determined as being equivalent to 9% of conveyance income'.

⁶⁶ See Appendix C, paragraph 95a.

⁶⁷ See Appendix C, paragraph 90.

⁶⁸ See Appendix C, paragraph 93.

⁶⁹ This is because from 2007 onwards PNGL receives a business rates allowance on determined revenues. In so far as PNGL does not recover the full economic value of its revenue under-recoveries, it would not receive a business rates allowance on revenues that are not recoverable and would therefore not be funded twice for such revenues. In other words, PNGL only receives funding for business rates for those revenues it actually generates, but it does not receive funding for business rates on revenues that it forgoes because of the penal rate of interest that is applied to revenue under-recoveries. The scope for being funded twice is therefore reduced by the effect of the penal interest rate.

⁷⁰ Although we do not think that including this effect would have a material impact on PNGL's calculations.

⁷¹ See also Appendix C, paragraph 86.

⁷² See Appendix C, paragraph 134.

⁷³ See Appendix C, paragraph 87.

⁷⁴ See Appendix C, paragraph 87.

- 5.111 On the basis of the information available to us it therefore seems that the negotiations with the VLA that PNGL referred to had already been taken into account when setting PNGL's business rates allowance in PC01. PNGL has not provided any other reasons why business rates outperformance in PC01 should not be attributed to revenue under-recoveries.
- 5.112 We therefore find that it is appropriate to make a TRV adjustment for business rates outperformance for both PC01 and PC02.
- 5.113 Following our provisional determination PNGL and UR provided detailed submissions on the appropriate adjustment to business rates outperformance related to revenue under-recoveries for both PC01 and PC02. We reviewed these calculations and compared them with the adjustment to business rates outperformance in our provisional determination.
- 5.114 A number of factors identified in the evidence provided by PNGL in response to our provisional determination (and in PNGL's response to our questions) support a reduction in the business rates adjustment for PC02 (compared with our provisional determination of £5.3 million). These include the fact that the business rates allowance in PC02 was set on the basis of expected revenues that were lower than allowed PC02 revenues⁷⁵ and that negotiations with the VLA contributed to business rates outperformance in PC02 (through the reduction of the percentage applied to the rateable value from 9 to 6 per cent) and that PNGL was not able to recover the full economic value of the revenue under-recoveries (due to the penal interest rate that was applied to revenue under-recoveries). We were persuaded that these factors showed that there should be some reduction.
- 5.115 We also looked at the appropriate level of a TRV adjustment for PC01.
- 5.116 We considered how to calculate an adjustment to business rates outperformance on the basis of the issues identified and the information available to us. However, we decided not to perform detailed calculations given that it would not be possible today to make an exact calculation of the appropriate adjustment to business rates outperformance given that not all the information necessary for an exact calculation appeared to be available. We also think that performing such detailed calculations would not be proportionate considering that the overall adjustment is only around 1 per cent of the value of the 2012 TRV.
- 5.117 We also considered the following points raised by UR and PNGL:
- (a) UR's reasoning that there is a further risk of customers paying twice for business rates because PNGL negotiated lower business rates in earlier periods in exchange for higher rates in later periods.⁷⁶
 - (b) UR's reasoning that business rates outperformance related to the reduction of the percentage applied to the rateable value from 9 per cent to 6 per cent as a result of PNGL being granted market development costs, and should not be retained by PNGL.⁷⁷
 - (c) PNGL's reasoning that some of the outperformance on business rates related to revenue under-recoveries in the transmission business and no adjustment should

⁷⁵ This is because the calculations PNGL provided to us did replicate the business rates allowances for PC02 when using revenues that were different from the allowed revenues in PC02.

⁷⁶ See Appendix C, paragraph 136.

⁷⁷ See Appendix C, paragraph 135.

be made for business rates outperformance related to these revenue under-recoveries.⁷⁸

- 5.118 On balance we concluded that the reduction in the adjustment for business rates outperformance in PC02⁷⁹ (compared with our provisional determination) as set out in paragraph 5.114 is broadly offset by the additional adjustment for business rates outperformance in PC01.⁸⁰ We thought that a detailed calculation of the appropriate overall adjustment to business rates outperformance was therefore likely to be in the region of £5 million. We think that a full investigation of these matters, even if possible (given that full information on the exact calculation for the business rates adjustment does not appear to be available), would be unlikely to be significantly different. We therefore decided to make an adjustment to business rates outperformance in the round at a level of £5 million.
- 5.119 PNGL said that business rates outperformance was the result of inaccurate ex ante forecasts and the risk/benefit with inaccurate forecasts was retained by the regulated company and that our proposal effectively made business rates subject to a retrospective adjustment mechanism, even though this was not signalled ex ante.⁸¹
- 5.120 PNGL agreed that without an adjustment it would be funded twice for business rates that are associated with revenue under-recoveries, but PNGL said that this did not warrant a reopening of the TRV, because the risk of being funded twice was known when the 2006 TRV was agreed.⁸² However, we have not seen any evidence that UR was aware of this error at the time of the 2007 determination.
- 5.121 PNGL also said that no adjustment should be made to business rates outperformance, because the regulatory framework foresaw that business rates outperformance would be offset by the penalties on under-recovered revenues. We did not find any explicit statements in the 1996 licence or the PC01, PC02 and 2007 determinations that supported PNGL's view.
- 5.122 Overall, we think that an adjustment to the TRV is justified, because of the risk of PNGL recovering the business rates allowance twice for the same revenues. We consider it to be against the public interest for consumers to pay twice for the same expenditure item.
- 5.123 We have therefore removed the element of business rates outperformance in the period 1996 to 2006 that would have resulted in PNGL being funded twice for the same business rates expenditure from the 2012 TRV (including the associated capitalized financing), but have not made any other adjustments to the TRV in relation to capex and opex outperformance.

Other issues relevant to the overall public interest

- 5.124 We have also looked at a number of issues around outperformance which are relevant to the consideration of the public interest in Section 9, and of regulatory stability, see Section 8. These are on PNGL's argument that there has already been

⁷⁸ See Appendix C, paragraphs 93 & 94.

⁷⁹ PNGL's estimates indicated a reduction in business rates outperformance in PC02 of around 50 per cent compared with our provisional determination.

⁸⁰ We calculated an approximate adjustment for business rates outperformance in PC01 on the assumption that all of the business rates outperformance in PC01 was due to revenue under-recoveries. However, we also took into account that PNGL is not able to recover the full economic value of the revenue under-recoveries in PC01 through the 2006 TRV. We therefore reduced the amount of business rates outperformance by 50 per cent.

⁸¹ See Appendix C, paragraph 95c.

⁸² See Appendix C, paragraph 95c.

sharing of historic outperformance with consumers, its argument on whether or not there were exceptional circumstances that justified consideration of a change to previously determined components of the TRV, and whether there was notice given that historic outperformance might be reviewed and removed from the TRV, or alternatively whether there were indications that it would not be re-examined.

Whether there had been previous sharing of outperformance

- 5.125 PNGL argued in its response to UR's consultation that efficiencies achieved between 1996 and 2006 had already been shared with consumers, and when viewed in conjunction with concessions it thought it had made in the 2006 'agreement' on the package of modifications, then overall it considered that only its share of outperformance had entered the TRV while in effect consumers had already received a substantial benefit from past outperformance. PNGL regarded the operation of the ratchet mechanism as a fundamental part of the process of sharing efficiency gains arising from outperformance between the company and consumers. In addition, PNGL stated that the 2006 'package' was designed to share value appropriately between PNGL and consumers, while in some cases PNGL kept the value associated with its 1996 licence (such as in respect of cost outperformance), while in other cases value passed to customers (such as in respect of the reduction in the allowed rate of return), see Appendix C, paragraphs 55 to 57. Therefore, it considered that the proposed adjustment double counted the share to be attributed to consumers, to the detriment of PNGL.
- 5.126 UR rejected this, stating that the sum for outperformance set in the 2007 licence modifications did not include sharing with consumers based on regulatory practice elsewhere.⁸³ UR said that while the ratchet mechanism could provide benefits to customers, outperformance itself was simply the difference between actual and allowed capex, and this number had not in any way been shared with customers (see Appendix C, paragraph 19). UR said that its view of sharing of outperformance had always referred to the period over which the outperformance would remain in the asset base.⁸⁴ UR said that PNGL had not presented any evidence to demonstrate that there was sharing in the way in which the term was usually understood.⁸⁵
- 5.127 PNGL said that UR's opening position in the negotiations that culminated in the 2006 'agreement' on the package of modifications, was that PNGL should only retain a proportion of outperformance where it could be shown that this outperformance benefited customers (see Appendix C, paragraph 62). It said that these benefits should then be shared between customers and shareholders. UR therefore proposed a series of treatments of capex outperformance where only a proportion was included in the OAV. As part of this process, PNGL said that UR proposed other measures which benefited PNGL such as a higher rate of return or an environmental grant, or a social/environmental allowance. However, this was not in the end enacted. PNGL said that the fact that it was allowed the full value of capex outperformance but excluded the social/environmental allowance indicated that UR was effectively compromising over the appropriate treatment of outperformance.
- 5.128 PNGL also said that if UR intended to make the adjustment to TRV, there was no reason why it should have waited to 2012; rather it would have been simpler and more transparent to make this adjustment when the licence was modified in 2007.⁸⁶

⁸³ UR [initial submission](#), paragraphs 3.26d & 3.30d.

⁸⁴ UR [supplementary submission](#), paragraph 2.93.

⁸⁵ UR [supplementary submission](#), paragraph 2.33.

⁸⁶ PNGL, [statement of case](#), paragraphs 4.15–4.20.

- 5.129 PNGL detailed some elements of the ‘package’ which it said represented value it had given up:⁸⁷
- (a) ‘Legacy contracts’ refer to PNGL’s contracts for the supply of gas to large customers that were agreed before there was effective competition in the supply of gas. These customers were supplied on terms determined by individual contracts. As part of the 2006 ‘agreement’, PNGL said that it gave up £9.6 million of value in respect of these contracts which it was unable to recover from customers because of the change in the way UR regulated the interface between PNGL’s supply and distribution businesses.
 - (b) Second, the rate of return allowed for PNGL was reduced from 8.5 to 7.5 per cent. At the time, PNGL estimated that this reduction was equivalent to giving up approximately £30 million of value relative to the 1996 licence (in 2006 prices, approximately £34 million in 2010 prices).
 - (c) Third, PNGL was required to divest its transmission business. Although PNGL acknowledged that it was allowed to earn a premium to the agreed transmission asset base, it stated that the sale resulted in lost value to PNGL because the premium achieved was not in line with other premiums being achieved at the time for regulated network assets; and PNGL was forced to miss out on the less tangible, but real, benefits of running a transmission business.
- 5.130 PNGL argued that the 2006 ‘agreement’ was a negotiated package where in the round PNGL made some gains and some losses, but some of the concessions it made could (in its view) be regarded as equivalent to a sharing of some of the value of outperformance. It said that sharing of outperformance was a central part of the 2006 negotiations (see paragraph 5.127).⁸⁸ PNGL stated that at the time of the 2006 ‘agreement’ UR had portrayed this as an agreement that was beneficial for consumers and represented a sharing of value (see Appendix C, paragraph 58 and 59). For example, paragraph 11 of UR’s publication ‘Phoenix Natural Gas Restructuring; Proposed Price Control Licence Modifications, 6 April 2007’ states: ‘The agreed OAV is a function of actual investment (opex and capex), under-recovered revenue and a sharing of cost out performance for the period 1996-2006’.
- 5.131 UR disagreed that the 2007 licence modifications resulted in significant value being ‘shared’ with or transferred to consumers. It stated that while the 2007 licence modifications provided benefits to consumers, it strongly disagreed with PNGL that they resulted in a transfer of value from the company to consumers, see Appendix C, paragraph 63.⁸⁹
- 5.132 UR acknowledged that it had started discussing sharing of outperformance with PNGL in 2006, but sharing had not been included in its determinations. It said that this was because its approach to outperformance did not impact on prices in the 2007 to 2011 period. However, it acknowledged that what it did not do was set out what it would do about outperformance in future price controls.
- 5.133 In regard to legacy contracts, UR said that the issue arose from the Phoenix supply business entering into long-term fixed-price contracts with customers, which were ultimately loss making for PNGL. It said that PNGL was not allowed to price

⁸⁷ In addition, the arrangements for the treatment of the recovery of deferred revenues in calculating the OAV (see paragraph 2.51) meant that some revenue was arguably given up, although the treatment reflected the fact that deferred revenues received a lower rate of return under the 1996 licence.

⁸⁸ See also Appendix 5.1, paragraph 55.

⁸⁹ UR [supplementary submission](#), paragraph 2.134.

discriminate on these contracts and it was inappropriate that other customers should cover the costs of these commercial decisions. It did not therefore see this as a transfer of value to customers, and in any case it did not see these losses as a matter for the distribution business. Rather, the losses were incurred in the supply business (see Appendix C, paragraphs 66 and 67).

- 5.134 UR said that the reduction in the allowed rate of return was not a transfer to consumers because the new regulatory framework that was put in place in 2007 substantially reduced shareholders' exposure to risk, and in any case the one percentage point reduction in the rate of return did little more than track the downward reduction in the cost of capital that had been observed across the regulated sectors in the UK between 1996 and 2007 (see Appendix C, paragraph 65).
- 5.135 In regard to the sale of transmission assets, UR stated that PNGL was able to achieve a premium for the sale of the transmission (see Appendix C, paragraph 64). UR also said that other claimed concessions were similarly not applicable (see Appendix C, paragraphs 68 to 70).
- 5.136 We note that at the time of the 2007 licence modification, there was no attempt within the determination documentation to evaluate whether or to what extent the package represented a sharing of accumulated outperformance between PNGL and the customers, and we have not seen any evidence to suggest that the proposals were ever evaluated in this way at the time.

Assessment

- 5.137 We agree that the ratcheting mechanism (as set out in paragraph 5.2) provides benefits to customers, but we think that it is misleading to characterize this as a sharing of outperformance. Ratcheting is a forward-looking concept in that the regulator sets challenging forecast costs. These costs should be revised according to a variety of sources of information, such as awareness of potential efficiencies, technical progress, benchmarking against efficient comparators and so on, as well as the extent to which there was past outperformance. So it is possible for a regulator substantially to cut projected costs based on comparator companies even where the regulated company has not achieved any outperformance. We agree with UR that sharing of outperformance refers to a distribution of outperformance that has occurred, not just the operation of a ratchet system.
- 5.138 Taking account of the arguments set out above, we do not consider that the 2007 determination had the effect of sharing historic outperformance between PNGL and customers. This is because UR's arguments that PNGL's 'concessions' were justified in their own right rather than being part of an overall package including outperformance cannot be rejected. Also, given that all opex and capex outperformance was included in the 2006 TRV, despite discussions at the time about reducing this amount (see paragraph 5.127), we cannot conclude that historic outperformance had already been shared.

Exceptional circumstances

- 5.139 PNGL proposed in its submissions that actions to revisit and remove previously established elements of the TRV could only legitimately be considered in 'exceptional circumstances'. PNGL stated that there were no 'exceptional circumstances' to justify the revision of the treatment of historic outperformance. It said that no new information had come to light since the 2006 TRV was set that would support the 2012

TRV adjustment and that UR had all relevant information at the time of the 2006 'agreement' (see Appendix C, paragraphs 73 to 76).⁹⁰ It said that an adjustment was necessary only to correct a mistake or logical error.⁹¹ It also said that it was not making excessive returns which might indicate that past determinations had been inappropriate (see paragraph 2.78 and Appendix C, paragraphs 77 and 78).

- 5.140 UR considered that its PNG12 determination was consistent with its original intentions and with good regulatory practice, and was an appropriate determination in the public interest based on the current situation and the balance of its objectives.
- 5.141 While it did not claim that it had received additional information that required a change of approach, UR said that it saw 2007 as representing a new beginning for the PNG1 model where there was a clean break with the 1996 licence and any expectations enshrined in it. It said that this was beneficial to PNG1 in many areas and UR said its treatment of deferred capex and sharing of outperformance in the 2012 TRV adjustment was considered in the context of this unique set of circumstances.

Assessment

- 5.142 We recognize that no significant new information or changes of environment and circumstance have emerged since 2007. However, we do not agree that this necessarily means that a regulator cannot reconsider previous decisions and make changes in order to better meet its statutory objectives. As discussed in paragraphs 9.112 to 9.120, stability and clarity are important aspects of regulation. Given the context of the substantial change in the regulatory system from 2007 we do not think that additional reasons are required to permit UR to consider the changes it has proposed, but such changes would require a clear and strong justification to be enacted. Our consideration of whether the 2007 determination represented a new beginning for the PNG1 model is set out in paragraphs 9.29 to 9.31.

Prior indications that historic outperformance would be revisited

- 5.143 UR said to us that it had intended in 2007 that historic outperformance in the TRV would be revisited, although it acknowledged that it had not been totally clear on this point (see paragraph 5.65). PNG1 told us that it received no notification prior to the 2011 consultation document that past outperformance would be revisited, and indicated that instead it had been led to believe that the treatment of outperformance in the 2007 determination was agreed and would not be changed (see Appendix C, paragraphs 6 and 25 to 38). We now consider whether UR had notified its intentions to revisit outperformance. The question of whether such changes may have implications for regulatory certainty and the cost of capital are addressed in Section 8.
- 5.144 UR said that none of the previous documents made any commitment to the sum of past outperformance remaining in the PNG1 asset base until 2046 (as PNG1 asserted),⁹² or that either these or the correspondence that was published at the time of the modifications could be taken to imply that benefits should not be shared. UR also said that it implemented this sharing using its licence modification powers.⁹³

⁹⁰ PNG1 [statement of case](#), paragraph 1.47.

⁹¹ PNG1 [response](#), paragraph 6.2a.

⁹² UR [PNG12 determination](#), paragraph 7.8.

⁹³ [ibid](#), paragraph 7.6.

- 5.145 UR's and PNGL's views of what was stated in the consultation documents and reports in 2007 are set out in Appendix C, paragraphs 27, 29, 30, 39, 40 and 43.
- 5.146 Both parties quote the same sections of the 6 April 2007 Draft Licence Modification. In regard to the OAV, the section in its entirety states (our emphasis added):
9. Unlike the original licence formulae which were based on discounted cash flows over the 20-year project period envisaged in 1996 the proposed modifications make explicit the regulatory asset value and how this is determined at each price control review.
10. The reference point for establishing the regulatory asset value for the beginning of the extended recovery period (the OAV) was that allowed under the original licence formulae. As previously explained, Phoenix has been under recovering relative to allowed revenue. However, over the period 1996-2006 Phoenix had outperformed relative to forecast costs at least partially offsetting the effect of under recovered revenue.
11. The agreed OAV is a function of actual investment (opex and capex), under-recovered revenue **and a sharing of cost out performance for the period 1996-2006.**
12. Under recovered revenue was allowed to earn a return significantly less than the regulated rate of return agreed in 1996 and was based on base rates which have averaged around 2% real over the period.
13. **Out performance for the period 1996-2006 is shared between customers and Phoenix based on regulatory practice elsewhere** while the net cash flow over the period established the base for the OAV.
14. These give an OAV of £316m at end of 2006 in 2006 prices. This may change slightly on submission of the audited 2006 regulatory accounts in June 2007.
- 5.147 UR indicated that paragraph 13 should be interpreted to show that mechanisms would be applied to share outperformance based on regulatory practice elsewhere. PNGL said that it interpreted these statements as saying nothing about future sharing of outperformance (see Appendix C, paragraph 25 to 38).
- 5.148 We note that there are no references to future revisions arising from sharing based on best practice in the PC03 determination. Also, there is no reference in the PC03 determination to any mechanism for changing the OAV (other than signalling of the 1999/2000 capex deferral review). UR, in 'Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination', Section 1.6, states 'As part of the Determination it has been decided that a number of areas within the cost base will be subject to future review. Some of these reviews will form part of a retrospective mechanism while others may involve a re-opener'. It then lists aspects of the determination subject to retrospective adjustment or reopener reviews. Past outperformance in the OAV is not included. As outlined by PNGL (see Appendix C, paragraph 29), UR did not establish a system that indicated when or how the OAV would be changed, and instead meant that any changes could be achieved only through a further licence modification. The projections UR made as part of its PC03 determination did not include any allowance or recognition of a possible change to the OAV. However, UR stated that this did not indicate that changes could not be

made and it had not made any indication that changes would not be made (see Appendix C, paragraphs 50 and 51).

- 5.149 UR said that it had indicated that deferred capex would be revisited in its PC03 determination, and therefore it would have been clear that the TRV could not be regarded as fixed, but instead could be subject to future change. However, we note that UR explicitly identified deferred capex and omitted reference to historic outperformance, which might create an impression that the omission was deliberate. UR said that the issue of outperformance did not impact on revenues in the 2007 to 2011 period and so was not included, because the focus of the issues covered by the price control (including deferred capex and other areas subject to review) was on issues that impacted on revenues in that period of PC03.
- 5.150 PNGL stated that it was given no indication by UR that past outperformance would be revisited until the 2011 consultation document (see, for example, Appendix C, paragraph 27). UR has not disputed that it did not make any direct reference to an intention to revisit it at the PNGL12 price determination before 2011. UR also acknowledged that its intentions for the revision of the TRV were only developed in 2011 (see Appendix C, paragraph 43). We also note that correspondence from UR to PNGL of 8 October 2007 (see Appendix C, paragraph 27(g)) stated ‘nor do we [UR] plan to reopen the November 06 agreement as part of our price control determination’. UR stated that this communication referred to concerns from PNGL that outperformance might be clawed back due to inefficiency and made no wider points about whether outperformance would be retained for 40 years (see Appendix C, paragraph 44). However, this particular sentence appears to us to imply that the 2006 ‘agreement’ on the package of modifications was not subject to any intention to revisit or remove outperformance.
- 5.151 UR said that whilst the documents might not make it completely clear how it would treat historical outperformance in the future, there was nothing which committed UR to allowing the outperformance to be retained until 2046.⁹⁴ UR indicated that its stated desire to adopt an approach that was consistent with regulatory practice elsewhere should have indicated that further sharing of outperformance could be expected. It said that extending the period of reward to outperformance to 40 years when moving to a standard regulatory approach would be a perverse decision. UR acknowledged that proposals for sharing underspend by reducing the OAV had been discussed with PNGL in the build-up to the 2007 licence modifications, however, in the end the capitalized value of underspend that went into the OAV did not include sharing.⁹⁵ While this indicates that the issue was under consideration, UR then dropped it from its final determination and made no direct reference to the possibility of revisiting it.
- 5.152 PNGL said it was not possible for UR to believe that PNGL could have had an ‘objective basis’ for expecting that UR would remove parts of historic outperformance from the TRV in its PNGL12 determination. This, PNGL said, had the effect of removing the undepreciated outperformance component from the 2006 TRV, which completely undermined the value sharing that underpinned the 2006 ‘agreement’ (see Appendix C, paragraph 36 and 38). PNGL stated that UR’s actions (such as embodying the TRV in its licence together with a methodology for recovery of the full value over the 40-year period), and its other conduct including its financial modelling (where UR’s models assumed no future adjustments) and discussions with PNGL—

⁹⁴ UR initial submission, paragraph 1.11.

⁹⁵ UR initial submission, paragraph 2.30.

see Appendix C, paragraphs 28 to 32 and 35) had led PNGL to expect that there would be no revisiting of historic outperformance in the TRV.

- 5.153 UR indicated that it was obliged to consider what determination accorded with the public interest. It said that the importance of regulatory certainty must necessarily be considered in light of all other relevant factors which were appropriate to consider in any price control review.⁹⁶ We note that UR undertook a public consultation before reaching its determination. UR said that it treated PNGL fairly as PNGL had the opportunity to comment on UR's proposals as part of the consultation process.⁹⁷
- 5.154 In relation to consultation, CCNI expressed some concerns. Particularly in respect of the 2007 determination, where it felt that the positive messages about the settlement that were expressed by UR were not consistent with the issues around the TRV subsequently identified in the 2012 determination. It said that it had not had sufficient information of the details of the determinations to be able to make a full assessment and ensure it was able to make an informed judgement when participating in the consultation.

Assessment

- 5.155 We are not persuaded that UR signalled that there was a likelihood or possibility that the outperformance element of the OAV would be revisited. We understand that UR and PNGL had discussed further sharing of the outperformance in 2006 but this had not been done in the 2007 determination and no comment was made on the possibility of returning to this subject. The references to sharing according to best practice are ambiguous as to whether they apply to what had already been agreed. For example, looking at paragraph 13 of the 6 April 2007 Draft Licence Modification (see paragraph 5.146), while UR said that this indicated future sharing of outperformance on the basis of regulatory practice elsewhere, in the context it is applied, it is not clear to us that it is referring to the possibility of a future revision of the TRV. Rather, paragraph 14 would seem more likely to be suggesting that the factors discussed in paragraph 13 had already been taken into account, and the only anticipated changes were those arising from submission of the regulatory accounts.
- 5.156 This is reinforced by the way the 2007 determination was implemented. Such actions are consistent with there being no intention to revisit the OAV but are hard to consider consistent with any intention to reopen it. If there was an intention to revisit the OAV at that time, it seems very unlikely that:
- UR would have raised an intention to adjust the OAV and then dropped that intention without making any reference to its intentions until 2011;
 - paragraph 9 of the 6 April 2007 Draft Licence Modification (see paragraph 5.146) would have stated that it was making explicit the regulatory asset value and how this is determined at each price control review;
 - UR would choose to make no clear reference to its intentions despite it having a large impact on the future revenues for PNGL and also impacting on the prices customers pay, either publicly or in communications with UR;

⁹⁶ UR [comprehensive response to comments on draft proposal \(2012 decision\)](#), p4.

⁹⁷ UR [comprehensive response to comments on draft proposal \(2012 decision\)](#), p10.

- UR would not have mentioned this to the rating agencies when PNGL issued its bond in 2009, considering that such future sharing would have a material impact on the financial ratios once implemented, in particular the net debt/RAB ratio; and
- UR would have chosen to have implemented the 2007 determination and licence changes in the way it did, certainly without further explanation.

5.157 If UR had anticipated that it would reopen the OAV, then the lack of clarity in making parties aware at the time of the 2007 determination denied PNGL the opportunity to make an informed judgement on whether to appeal the determination at that time.

5.158 We conclude that prior to the public consultation in 2011, PNGL would not have had reason to expect that there was a likelihood or possibility that the outperformance element of the OAV would be revisited. UR indicated that it never stated this would not be revisited. We do not accept that UR's silence on the possibility of future revisions lends support to its case. Various factors indicated against the possibility of such revisions, and it seems implausible that UR would have remained silent on such an important point if it had been part of its intentions.

5.159 We also note that it is important that CCNI and any other relevant bodies have sufficient information available to them so that they can properly participate in public consultations. While this is not part of our findings, and in light of the EC Commission interpretation note on Article 40, which indicates that it sees it having relevance not only in the decisions that regulators take, but also in liaison and transparency between regulator and other consumer bodies, we hope that in future fuller information will be available where permitted and practicable.⁹⁸

Issues relating to WCA outperformance and volume underperformance

5.160 We now consider issues relating specifically to the WCA and volume underperformance elements of historic outperformance.

WCA outperformance

5.161 PNGL said that the 1996 licence calculated outperformance on a cash basis, rather than an accounting basis. The purpose of the WCA adjustment within the original licence was to adjust the accounting costs and revenues associated with opex so that they could be dealt with on a cash basis.⁹⁹

5.162 PNGL said that if it was able to find more efficient ways of managing its business that allowed it to spend less cash (as opposed to accounting cost) within each control period, it was able to retain the benefit of this outperformance under the original licence. This treatment was appropriate since improving cash management was another example of cost efficiency that could be incentivized. Any outperformance in WCA should therefore have been treated as opex outperformance more generally according to the terms of the original licence.¹⁰⁰

⁹⁸ Article 40 states 'The Commission's services consider that this interaction should, as a minimum, take the form of open and transparent public consultation between the relevant bodies and provide for the capacity to share information'. Section 3, Commission Staff Working Paper, Interpretative Note on Directive 2009/72/EC Concerning Common Rules for the Internal Market in Electricity and Directive 2009/73/EC Concerning Common Rules for the Internal Market in Natural Gas Retail Markets, Brussels, 22 January 2010.

⁹⁹ PNGL [statement of case](#), Annex 6, paragraph 14.

¹⁰⁰ PNGL [statement of case](#), Annex 6, paragraph 15.

- 5.163 UR said that it and PNLG had differing views on how to treat WCA outperformance in the 2006 'agreement'. PNLG initially argued that WCA outperformance of £9.4 million (2006 prices) should be included in the 2006 TRV whilst UR argued that the 1996 licence did not intend to allow for WCA outperformance. The different positions arose because of an ambiguity in the 1996 licence. Whilst it was clear in Condition 2.3.15 (in the definition of allowed WCA adjustment) that audited numbers would be used for the working capital adjustment which showed a clear intention to use actuals, the allowed revenue formulae in the licence did not contain a mechanism to account for variances from forecasts. Having considered PNLG's representations, UR said that it agreed to add an amount of £5 million to the OAV, which PNLG accepted. UR said that that the £5 million was never described as sharing at the time of the 2006 'agreement', no sharing of outperformance was implemented in 2007 and UR said it still did not regard it as such today.
- 5.164 PNLG said that the licence did not provide any justification for allowing less working capital into the 2006 OAV than allowed under the 1996 licence. It said that it agreed to adjustments going beyond those permitted by the licence (ie to include only £5 million for WCA outperformance, even though total WCA outperformance calculated in accordance with the 1996 licence was £10.3 million¹⁰¹) as part of the overall package of measures within the 2006 'agreement'.¹⁰² In response to UR's statement that the adjustment to WCA outperformance in the 2006 TRV was due to an ambiguity in the licence (see paragraph 5.163), PNLG said that there was no ambiguity in the licence that would have justified the WCA adjustment in the 2006 'agreement'.
- 5.165 PNLG said that the unrecovered £5.3 million of WCA outperformance represented additional sharing of value in favour of customers,¹⁰³ and therefore that UR's 2012 TRV adjustment for WCA outperformance was an unjustified double sharing of outperformance.
- 5.166 UR said that its 2012 TRV adjustment was applied to all outperformance (whether opex, capex, volumes, WCA), which had all been treated the same. The adjustment was made to implement sharing consistently with regulatory practice elsewhere. Outperformance, including WCA, had not been shared previously with consumers.
- 5.167 UR said that the changes made in 2007, with the revised licence moving PNLG away from the original discounted cash flow model to a more standard RAB model was a transition to a new framework. UR said that it did not seek to reconcile all elements of the 1996 regime with the 2007 licence modifications, for example under-recoveries. UR said that it was clear from the 2007 licence modification consultation that this new regime also included the sharing of outperformance.
- 5.168 UR said that since 2007, WCAs were treated as a pass-through item.

Volume underperformance

- 5.169 PNLG said that under the 1996 licence, PNLG's revenues were linked to achieved volumes. Overall, PNLG underperformed relative to volume targets between 1996 and 2006. PNLG said that at the time of the 2006 'agreement', UR treated volume underperformance in a symmetric way to the opex and capex outperformance, and

¹⁰¹ PNLG said that at the time of the 2006 'agreement' WCA outperformance was £9.4 million, but was later updated for PNLG's actual performance to £10.3 million. See PNLG [statement of case](#), Annex 6, paragraph 16.

¹⁰² PNLG [statement of case](#), paragraph 5.20a.

¹⁰³ PNLG [statement of case](#), Annex 6 paragraph 17.

so it was deducted in the calculation of the OAV.¹⁰⁴ It said this reduction was £3.6 million.¹⁰⁵ PNGL said that volume underperformance should be treated as per the 1996 licence (as was the case in the 2006 'agreement').

Our assessment

- 5.170 We considered whether PNGL's and UR's submissions disclosed errors in UR's previous treatment of WCA outperformance and volume underperformance, for example situations where there were calculation errors. UR included WCA outperformance in the 2006 TRV without signalling further adjustments. We did not think that any errors in the prior treatment of WCA outperformance have been indicated. We accept that some WCA outperformance occurred in the period 1996 to 1998, ie before the PC01 determination in 1999. However, as set out in paragraphs 5.94 to 5.96, we thought that UR was aware that its PC01 determination would effectively grant some opex and capex outperformance for the period 1996 to 1998 in its PC01 determination (which UR took in 1999). We cannot exclude the possibility that UR did not have a similar intention for WCA outperformance. We note that UR included WCA outperformance in the 2006 TRV without making an adjustment for the WCA outperformance that accrued in 1996 to 1998. In addition, PNGL was incentivized under the 1996 licence to achieve efficiencies in relation to the WCA, and UR therefore may have intended to reward PNGL for some of the WCA-related outperformance that accrued in the period 1996 to 1998 when it made its PC01 determination.
- 5.171 We note that there was acceptance between UR and PNGL to allow a proportion of the WCA outperformance into the TRV in the 2006 'agreement'. This was due to different interpretations of the 1996 licence. Under these circumstances we think that UR's decision to include a particular WCA outperformance value in the TRV as it did was reasonable and appropriate and within its reasonable regulatory judgement.
- 5.172 We note that PNGL did not specifically dispute UR's treatment of volume underperformance. We have not identified any technical errors in the way that UR included volume underperformance in the 2006 TRV.

¹⁰⁴ PNGL [statement of case](#), Annex 6, paragraph 13.

¹⁰⁵ PNGL [statement of case](#), Annex 6, paragraph 10.

6. The 1999/2000 capex deferrals

Introduction

- 6.1 This section covers our assessment of the appropriate treatment of a specific subset of capex deferrals—the 1999/2000 capex deferrals. As set out in Section 5 (see paragraphs 5.15 to 5.17) capex deferrals in this context are workstreams for which PNGL received full funding in UR’s determinations (in PC01, PC02 and PC03), but which were either completed later than originally planned or which, by 2011 (ie the end of PC03) had still not been completed. Whilst PNGL explained to us that UR’s determinations were not done on a project-by-project basis, we understand that for a subset of PNGL’s overall capex deferrals PNGL identified a list of projects, as part of the PC03 and PNGL12 determinations, which were subject to deferral. The full list of projects is outlined in Appendix 4 of the PNGL12 determination and this is reproduced in Appendix D, paragraph 88 and Table 1. The initial allowances for these projects were included in UR’s PC01 determination in the years 1999 and 2000 and we therefore refer to them as the 1999/2000 capex deferrals in the remainder of this document.¹
- 6.2 The TRV at the end of the PC03 charge control includes £6.5 million of funding related to the original capex allowances for the 1999/2000 capex deferrals, even though PNGL has either not spent these allowances or spent them later than planned.² In addition to this, it includes capitalized financing costs (ie the cost of raising funds for the investment even though PNGL did not actually incur these financing costs) and management fees related to the 1999/2000 capex deferrals. The TRV (including these elements) generates revenues (paid for by customers) for PNGL through depreciation charges and the financing costs (WACC).
- 6.3 We therefore looked at these elements to decide whether it is against the public interest for them to remain in the TRV and if so, what actions should be taken.
- 6.4 The reason why we are considering the 1999/2000 capex deferral projects separately from the discussions in Section 5, is that in this case the PC03 and PNGL12 determinations specifically identify the projects (therefore we can associate specific deferrals with particular projects and their timing, in contrast to the deferred capex discussed in Section 5) and the PC03 determination explicitly stated that UR was planning to undertake a review of the appropriate treatment of the 1999/2000 capex deferrals. Paragraph 6.3 of UR’s PC03 determination states in relation to revisiting the treatment of the 1999/2000 capex deferrals:

The Utility Regulator wishes to consider the appropriateness of deferred capex (4/7 bar and Governors) that is planned for future construction, and will review the planned activity to ascertain when/if it will be carried

¹ PNGL said that UR had used a wider set of projects in the PNGL12 determination for the 1999/2000 capex deferrals than implied in the 2007 determination. UR identified projects worth £6.499 million (in 2010 prices) in the PNGL12 determination, whereas the 2007 determination (through the 2006 TRV) contained £5.257 million in 2006 prices (equivalent to £5.919 million in 2010 prices). We think that the PC03 determination (and PNGL12 determination) does not explicitly refer to the £5.2 million deferred capex in the 2006 TRV, but to a list of projects and we have seen no evidence that the list of projects referred to in the PC03 determination was different from the list of projects included in the PNGL12 determination. We also think that UR’s comments in the PC03 determination and in particular as set out in paragraph 6.4 is more likely to refer to the list of projects rather than the allowance included in the 2012 TRV. We also thought that the project list identified specific projects, which was much more detailed than the calculation of the deferred capex element of the 2006 TRV and note in this context that some deferred capex was also included in the capex outperformance element of the 2006 TRV. We therefore thought that the project list was a more appropriate basis for the assessment of the 1999/2000 capex deferrals than the amount of deferred capex explicitly labelled as such in the 2006 TRV. We also think that the small difference (of around £1 million out of a total TRV of around £400 million) did not justify further investigation as we thought that doing so would be disproportionate.

² We note, however, that UR, in the PC02 and PC03 determination, made offsetting adjustments by reducing PNGL’s capex forecasts to take into account PNGL’s 1999/2000 capex deferrals (see paragraph 6.10).

out and if it would be in the customer interest to use the “deferred” cash within the asset base for other construction activities. This analysis will form one of the reviews to be conducted during PC03.³

- 6.5 We also noted that the majority of the 1999/2000 capex deferrals have not been completed by the end of PC03 (and that these deferrals are therefore for longer periods than the other deferrals originating in the period 1996 to 2006).
- 6.6 Below we first set out relevant background material to the 1999/2000 capex deferrals and the arguments presented by UR and PNGL concerning the 1999/2000 capex deferrals (including the management fee and capitalized financing on these deferrals). We then set out our assessment of whether these sums should remain in the TRV and if not, what actions should be taken.

Background

The reasons for the 1999/2000 capex deferrals

- 6.7 PNGL said that in 1998 it decided to accelerate its network build programme compared with the Mandatory Development Plan in its licence and it was because of this that the 1999/2000 capex deferrals were made.⁴
- 6.8 As set out in paragraph 2.27, PNGL said that its original strategy was that all the capacity that would ever be needed in the network would be undertaken at the same time as the original construction of that part of the network (the ‘build it and they will come’ strategy). However, following lower than expected connections of new customers PNGL accelerated the network build by switching to a ‘build to meet customers’ needs’ approach (where the connection of new customers was prioritized, for example to capture new-build and refurbishment programmes). PNGL said that under this approach, network that was not an absolute necessity, such as network that provided increased security of supply or increased capacity in an area, was constructed only as and when the need arose (which led to the 1999/2000 capex deferrals).⁵
- 6.9 PNGL said that the accelerated roll-out strategy adopted in 1999 was factored into the allowed costs determined by UR at the first price control review (PC01), and that this effectively endorsed PNGL’s revised strategy.⁶

The general treatment of deferred capex by UR in its PC02 and PC03 charge control decisions

- 6.10 We understand that UR’s treatment of deferred capex in the PC02 and PC03 determinations was as follows:⁷
- (a) For connections, UR (in its determinations) allowed PNGL funding to cover the cost of connecting a target number of customers to the gas network. UR included a retrospective adjustment mechanism from PC02 onwards, which provides for an ex post adjustment to the capex allowances in the determination for connections, taking into account the actual number of connections made. In

³ UR PC03 determination, paragraph 6.3.

⁴ PNGL [statement of case](#), paragraph 2.22.

⁵ See Appendix D, paragraphs 11–14.

⁶ PNGL [statement of case](#), Annex 3, paragraphs 5 & 18.

⁷ See, for example, Appendix D, paragraphs 146, 147 & 148, 152–154, 158–160, 166, 167, 169 & 172.

effect this mechanism provides for an adjustment for capitalized financing and the management fee for the deviation between the number of connections in the determination and the actual number of connections. From PC03 onwards these adjustments are made in the TRV at the beginning of the next charge control.

- (b) For other capex deferrals (other than connections), UR, in its PC02 and PC03 determinations took capex deferrals in prior charge controls (ie capex deferrals made in the period 1996 to 2006, which includes the 1999/2000 capex deferrals, and also includes other capex deferrals) into account by reducing PNGL's capex allowance in the new charge control (as the deferred capex projects had already been funded in previous charge controls). This adjustment was not made in cash terms, but by a reduction in the forecast quantities of physical assets built⁸ in the new charge control (multiplied by the unit costs applying in the new charge control). We understand that PNGL could, in the PC02 and PC03 charge control, use the funding for deferred capex projects either for the deferred projects or to deliver alternative projects.
- (c) In PC03 UR implemented a new approach⁹ for the treatment of deferred capex (other than connections) that accrued in PC03 so that any future capex deferrals that happened from 2007 onwards would be removed from the TRV by retrospectively reducing the capex allowances in PC03 (this would be done via an adjustment to the opening TRV in the next charge control). The treatment for capex deferrals from 2007 onwards (other than connections) includes a removal of capitalized financing benefits, but does not include an adjustment for the management fee.¹⁰

6.11 We also understand that UR did not propose any significant changes to its treatment of future deferred capex in the PNGL12 determination compared with the PC03 determination. However, we note that because the management fee in PNGL12 is included in unit costs, rather than set out separately (as in PC03), all future retrospective adjustments for deferred capex will effectively include a management fee adjustment.¹¹ We also note that neither PNGL nor UR considered that the regulatory approach applying to capex (including capex deferrals) from 2007 onwards was in dispute.

PNGL and UR's arguments on the 1999/2000 capex deferral projects

UR

- 6.12 UR said that PNGL's asset base had been unduly inflated as a result of PNGL benefiting from the early receipt of allowances related to the 1999/2000 capex deferrals versus when the work actually took place and that PNGL should not retain the benefit of a failure to deliver assets or the delivery of assets later than originally scheduled.¹²
- 6.13 UR said that PNGL's 'build it and they will come' strategy was not efficient as optimal network development required that it be constructed as and when required. UR said

⁸ This adjustment would be made in the year in which the deferred projects were planned to be built. For example, if a capex project was deferred into 2014, UR would reduce PNGL's projected capex in 2014 to take into account that funding for this project had already been provided previously.

⁹ We understand that the PC03 charge control established a formal framework for the treatment of outperformance and deferred capex for the period of 2007 onwards. This framework was not raised as a subject of disagreement between PNGL and UR.

¹⁰ UR [PNGL12 determination](#), Annex 5, paragraph 13.

¹¹ See Appendix D, paragraph 125

¹² Appendix D, paragraph 85.

that it would not be efficient to build pipelines that were not required for over 20 years.¹³

- 6.14 UR said that in PC01 it expressed concern about the lack of transparency and robust justification for PNGL's proposed accelerated network build programme. The associated capex was allowed in the end, but on the condition that PNGL would adopt a series of capex-related recommendations. UR said that some of these issues continued in PNGL12.¹⁴
- 6.15 UR also said that the 1999/2000 capex deferrals were different from other capex deferrals in that it was unlikely that sufficient alternative projects were available to which the 1999/2000 capex deferrals could be applied, ie that it was unlikely that these large sums could be offset against alternative future projects.¹⁵
- 6.16 UR, in its PNGL12 determination, made an adjustment for the 1999/2000 capex deferrals of £17.3 million (in 2010 prices). This adjustment had the following components:¹⁶
- (a) The original allowances for projects that were not completed in PC03 (£5.7 million).¹⁷ A management fee uplift of 20 per cent on the £5.7 million of projects that were not completed in PC03, ie £1.1 million.
 - (b) Capitalized financing¹⁸ (on all the 1999/2000 capex deferral projects) of £10.5 million, which can be subdivided into:
 - (i) capitalized financing for the period 1999/2000 to 2011 for those 1999/2000 capex deferral projects that were not completed by the end of PC03 (the original allowances for these projects were £5.7 million as set out in subparagraph (a)); and
 - (ii) capitalized financing for the period 1999/2000 to the time of completion for those 1999/2000 capex deferral projects that were completed by the end of PC03 (the original allowances for these projects were £0.8 million).
- 6.17 UR said that its proposed treatment of deferred capex (in removing it from the TRV) was symmetric to its treatment of projects that were originally not foreseen but were needed (and therefore retrospectively added to the TRV) and that its treatment mimicked competitive outcomes where companies would not be able to recover money for investments that were never made since if they tried to do so, competitors would undercut them.¹⁹

PNGL

- 6.18 PNGL said that the 1999/2000 capex deferrals were efficient, because PNGL met all of its output targets and the accelerated network strategy benefited customers

¹³ UR [supplementary submission](#), paragraph 2.38.

¹⁴ Appendix D, paragraphs 109 & 110.

¹⁵ Appendix D, paragraph 117.

¹⁶ See Appendix D, paragraphs 5–8.

¹⁷ The original allowance for those 1999/2000 capex deferrals that were completed in PC03 was £0.8 million. These projects are relevant for the capitalized financing calculation, but this amount was not included in the £17.3 million 2012 TRV adjustment for deferred capex. The total original allowances included in the list of 1999/2000 capex deferral projects used by UR was therefore £6.5 million (in 2010 prices).

¹⁸ This is the rate of return that PNGL is allowed to earn on allowances which have entered its capital base (whether or not the allowance has in fact been spent on capex).

¹⁹ Appendix D, paragraphs 90 & 91(e).

through more customer connections. PNGL also said that UR's consultants confirmed the efficiency of the 1999/2000 capex deferral projects.²⁰

- 6.19 In relation to UR's proposals to remove the capex deferral projects from the TRV, PNGL effectively said that UR should not have deviated from its previous treatment of capex deferrals originating in the period 1996 to 2006 for the purpose of regulatory consistency over time (which ensured predictability and stability of the regulatory regime) and therefore the 1999/2000 capex deferrals should be netted off future capex allowances.²¹
- 6.20 PNGL said it accepted that UR had previously signalled its intention to consider further the treatment of the 1999/2000 capex deferrals.²² However, PNGL said that UR's methodology (see paragraph 6.16) for calculating the 2012 TRV adjustment for the 1999/2000 capex deferrals was wrong because:²³
- (a) There was no separate provision in the 1996 licence for the treatment of deferred capex. PNGL said that both UR and investors therefore knew that, under the terms of the 1996 licence, deferred capex would be treated in the same way as any other capex efficiency.²⁴ PNGL also said that it was a feature of the 1996 licence that outperformance and deferral of capex spend should be treated in the same way as the actual investments in infrastructure.²⁵
 - (b) The 2012 TRV adjustment for deferred capex was inconsistent with the treatment of deferred capex that could reasonably have been expected given the precedent established by the PC03 determination and other public statements by UR, which was that deferred capex would be used to reduce future capex allowances (rather than to reduce the TRV).²⁶ PNGL also said that the magnitude of the adjustment for the 1999/2000 capex deferrals was entirely unexpected (because it included an additional adjustment for capitalized financing and the management fee); since it was inconsistent with the 2006 'agreement' on the package of modifications; the precedent established at PC03; and regulatory best practice.²⁷ PNGL also said that the 1999/2000 capex deferrals covered a broader set of projects than that captured in the 2006 'agreement' under the heading deferred capex.
 - (c) UR's proposal for deferred capex undermined any incentive on PNGL to optimize the timing of capex going forward,²⁸ and was not in line with regulatory precedent in Great Britain (because UR's adjustment was retrospective and because 100 per cent of the benefits of capex deferrals would be transferred to customers). UR's treatment was also contrary to the rules applying to deferred capex in the 1996 licence and changed, ex post, the incentives applying to PNGL in relation to deferred capex and this had the potential to undermine any incentive mechanism UR might wish to employ in future.²⁹

²⁰ See, for example, Appendix D, paragraphs 55, 58, 61, 62 and 68–70.

²¹ Appendix D, paragraphs 27–29.

²² PNGL [statement of case](#), paragraph 1.49 and Annex 7, paragraphs 10 & 11.

²³ PNGL [statement of case](#), Annex 7, paragraph 4.

²⁴ PNGL [statement of case](#), paragraph 3.13.

²⁵ PNGL [response](#), paragraph 7.1a.

²⁶ PNGL [statement of case](#), paragraphs 1.49 & 1.49b; Annex 9, p4; Annex 7, paragraph 4b, 10, 11 & 12.

²⁷ PNGL [response](#), paragraph 1.6b.

²⁸ PNGL [statement of case](#), paragraphs 1.49 & 1.49b and Annex 7, paragraphs 10 & 11.

²⁹ PNGL [statement of case](#), paragraph 4.41c.

(d) It also disagreed with UR's 20 per cent uplift to the deferred capex calculations for the management fee, because the management fee was largely fixed as part of the McNicholas contract.³⁰

Our assessment of the treatment of 1999/2000 capex deferrals

- 6.21 UR's reference to us effectively requires us to assess whether it is against the public interest for PNGL to retain those elements of the TRV that relate to the 1999/2000 capex deferrals. In this section we consider whether these elements are against the public interest. In addition, in Section 9, we consider whether the balance of the price control taken overall is or is not against the public interest.
- 6.22 In answering this question, we found it helpful to consider separately each element (as set out in paragraph 6.16) of the 1999/2000 capex deferrals, ie:
- (a) whether the original capex allowances for the 1999/2000 capex should remain in the TRV (although we acknowledge that, in principle, these sums do not directly impact on the public interest because their costs are offset, see paragraphs 6.33 and 6.34);
 - (b) whether the associated capitalized financing should remain in the TRV; and
 - (c) whether the associated management fee should remain in the TRV.
- 6.23 We thought that the wording 'deferred capex (4/7 bar and Governors) that is planned for future construction' in paragraph 6.4 indicates that UR's statement logically should only apply to projects that were planned for future construction by the time the review would be undertaken (in this case the end of PC03). It is therefore appropriate to divide the 1999/2000 capex deferrals into two groups. First, 1999/2000 capex deferral projects that were completed by the end of PC03, and second, 1999/2000 capex deferral projects that were not completed by the end of PC03 (ie that were still planned for future construction at the start of PNGL12).
- 6.24 As noted in paragraphs 5.5 and 5.11, both PNGL and UR agreed that the 1996 licence made no explicit provision for the treatment of deferred capex (other than the treatment of outperformance in general) and that the 1996 licence did not provide for a different treatment of deferred capex and opex and capex outperformance.³¹ We also note that the 1996 licence does not make any explicit reference to outperformance (in general or deferred capex in particular), but it appears that the treatment of any differences between the regulatory allowances and the actual out-turn expenditure is implicitly contained in the formulae specifying the setting of the price control. The 1996 licence, through the formulae contained therein, would treat all differences between allowed and actual expenditure as being retained by PNGL.³²
- 6.25 However, we note that UR had, in all its determinations from PC02 onwards, treated deferred capex in a different way from that implied by the 1996 licence (see paragraph 6.10).
- 6.26 As noted in paragraphs 5.18, there are reasons why the ability to defer capex may be beneficial, for example if it allows the company to time the sequence of capital investment more appropriately (and a company should not be incentivized to undertake

³⁰ See Appendix D, paragraphs 45–50.

³¹ Appendix D, paragraphs 23–26 and 93–95.

³² Appendix D, paragraphs 23–26 and 93–95.

pre-agreed investment regardless of any changes in circumstances), and PNGL told us its network roll-out was at times developed flexibly in response to promising market opportunities as they arose—see paragraph 2.27. PNGL told us that all its 1999/2000 capex deferrals were efficient and that it met all its output targets.

The original capex allowances for the 1999/2000 capex deferrals

- 6.27 As set out in paragraph 6.16, the TRV at the end of PC03 included £5.7 million of original capex allowances (for the 1999/2000 capex deferrals) that had not been spent by the end of PC03 and £0.8 million of the original allowances that had been spent in PC03.

1999/2000 capex deferral projects completed by the end of PC03

- 6.28 We think that the £0.8 million original capex allowances relating to those 1999/2000 capex deferrals that have been completed by the end of PC03 should be retained in the TRV as these are investments that PNGL made into the gas distribution network. We note that neither PNGL nor UR suggested a different treatment.

1999/2000 capex deferral projects not completed by the end of PC03

- 6.29 We have concluded that retention of the original capex allowances of £5.7 million for 1999/2000 capex deferral projects that have not yet been completed in the TRV is against the public interest for the reasons set out below.
- 6.30 These projects largely referred to capacity reinforcements that had fallen into abeyance (if not falling away permanently) when PNGL changed its strategy around 1999/2000. A distinguishing feature is the extent of time for which these projects have been deferred (by the end of 2011 they would have been deferred for a period of 11 to 12 years). This raises the question of when deferral of capex can be regarded as constituting an absence of investment. It would appear counter-intuitive to allow a regulated company inclusion in the TRV of an allowance to undertake capital expenditure that it has not undertaken for an extended period and/or that it is not going to undertake. PNGL has not yet made these investments. PNGL told us that these projects largely remained in its intentions and they would be required at some time. However, it appears to us now, given the revisions of the investment policy in 1999, that the need for these projects in the foreseeable future (if at all) has dropped away. As a general proposition, it seems that there must be some threshold where rather than considering deferrals as appropriate, one should consider that retention of seriously delayed, or irrelevant or superseded projects in the portfolio of intended investments is no longer appropriate, and they should be removed and only reinstated when they are immediately relevant to the current strategy. Put another way, deferral of capex is appropriate where customers may benefit from that, but not to the point where customers have to pay for the company not to undertake a project it did not intend to undertake (or not to undertake for a long period of time). Customers cannot be considered to be benefiting from such deferrals, rather the projects should not be in the allowances at all. Where that threshold lies can probably not be determined on a general basis but only by reference to the specific circumstances of each situation. We consider that in this case, the projects which have not been completed can now be regarded in that light as a threshold of more than 11 to 12 years is too great.

- 6.31 We also note that both PNGL's and UR's suggested treatment of the 1999/2000 capex deferrals that have not been completed by the end of PC03 involves a removal of the original allowances from the charges customers pay.³³
- 6.32 Having assessed that the original unspent allowances for 1999/2000 capex deferrals should be removed from the TRV, we now address the question of the appropriate adjustment mechanism. UR's preferred approach was to align the treatment of these amounts with the approach that it had set out in the 2007 determination for deferred capex arising in PC03; ie the amounts should be removed from the TRV. PNGL did not agree with this and argued that the unspent allowances should be kept in the TRV but future capex allowances should be reduced accordingly.³⁴
- 6.33 We think that the question of whether the adjustment for deferred capex is made by netting it off future capex allowances or by reducing the TRV is largely irrelevant because either option results (at least in principle) in the same impact on the revenue cap for PNGL (ie the financial effect of the two different treatments are, in principle, the same). This is because under PNGL's option the reduction is made to capex allowances and in UR's option in the TRV, but both options reduce the charges customers pay.³⁵ We do not think that there are strong reasons to prefer one treatment over the other, but on balance we agree with UR, that making a TRV adjustment is simpler as it does not require additional adjustments to forecast capex allowances. We therefore made the adjustment for the 1999/2000 capex deferrals directly in the TRV.
- 6.34 We note that there may be some financial differences between the specific calculation methods suggested by UR and PNGL. UR removed the original capex allowances for the 1999/2000 capex deferrals from the TRV. PNGL's suggested method, which would involve removing forecast asset volumes times forecast prices for these assets could produce different results, if the asset volumes and forecast asset costs are different from the implied asset volumes and asset costs in the original allowance for the 1999/2000 capex deferrals. We accept that this could lead to differences in the capex allowances removed from the TRV. However, we think that it is, in this case, more pragmatic to remove the original allowances. This is because, we were told, most of the 1999/2000 capex deferrals (in value terms) are not needed before 2020 and it would therefore be difficult reliably to forecast the expected costs. We also note that some of the 1999/2000 capex deferral projects have changed significantly since the original allowances were set (and at least one project is not needed anymore), which would further complicate the calculation of an adjustment using forecast asset costs.
- 6.35 We note that PNGL's suggested treatment would continue to reward PNGL with capitalized financing benefits for those 1999/2000 capex deferrals that have not been completed by the end of PC03 until they are built. We set out in paragraphs 6.45 to 6.63 why we do not think this would be appropriate. We also note that PNGL has retained the capitalized financing benefits for those 1999/2000 capex deferrals that have not been completed by the end of PC03 until 2006 and has therefore received a return for these deferrals.

³³ UR and PNGL only disagree how this is effected in the financial model: UR suggested to remove them through a reduction in the TRV, whereas PNGL suggested to effect the removal through a reduction in the capex forecasts. Where UR and PNGL disagree is mainly how much capitalized financing PNGL should retain for the 1999/2000 capex deferrals (which is addressed in paragraph 6.37 onwards).

³⁴ In this way we understood that there was a potential for PNGL to benefit from capitalized financing (we address capitalized financing in paragraph 6.37 onwards).

³⁵ See paragraph 6.31.

- 6.36 We also think that removing the original allowances reduces the risk to PNGL, as PNGL can now apply for funding for the remaining 1999/2000 capex deferral projects on the basis of actual efficient costs at the time. We therefore decided to remove the original allowances for the 1999/2000 capex deferrals that have not been completed by the end of PC03 from the TRV.

Capitalized financing and management fees

- 6.37 We now assess whether the inclusion in the TRV of capitalized financing and management fees relating to the 1999/2000 capex deferrals is against the public interest. This relates both to allowances for 1999/2000 capex deferrals that had been spent during PC03 and those that remained unspent at the end of PR03.

Capitalized financing

- 6.38 As set out in paragraph 6.16(b), the TRV, at the end of PC03 included capitalized financing relating to the 1999/2000 capex deferrals of £10.5 million. This consisted of capitalized financing for 1999/2000 capex deferral projects that were completed by the end of PC03 and projects that were not completed by the end of PC03.
- 6.39 One consideration in the decision of how much capitalized financing PNGL should retain for capex deferrals is the appropriate incentive mechanism in relation to capex deferrals. However, we are unable to perform an assessment now on what the appropriate incentive framework would have been at the time when the allowances for the 1999/2000 capex deferrals were granted. Whilst we have received related evidence from both PNGL and UR we think that a decision on the appropriate incentive package would require a thorough understanding of all the circumstances at the time, which would effectively require a retaking of the PC01 and subsequent determinations which we thought would be impossible to perform now with a sufficient degree of precision.³⁶ We did not find in Section 5 any technical errors in relation to deferred capex. We note that PNGL was, through the PC01 and subsequent determinations, incentivized to make capex deferrals and did so. We do not think that there is sufficient evidence to find that PNGL should not retain any capitalized financing benefit from the 1999/2000 capex deferrals, particularly considering that the PC01 and PC02 determination implicitly envisaged that PNGL should retain such capitalized financing benefits.
- 6.40 However, we thought that, in principle, it would not be appropriate for PNGL to retain capitalized financing benefits for capex deferrals indefinitely. This is for the same reasons as in paragraph 6.30. It is unreasonable to reward a company for an investment that has not taken place for an extended period, thus indicating that the investment was not required, or was not currently relevant. We think that in these instances customers cannot be considered to be benefiting from such a deferral.
- 6.41 We set out below what we consider the appropriate amount of time is for which PNGL should retain the capitalized financing benefits on the 1999/2000 capex deferrals. We do this first for those capex deferral projects that were completed by the end of PC03 and then for those that were not completed by the end of PC03.

³⁶ The evidence that we have seen provided mixed evidence. Some indicated that no incentives for capex deferrals should have applied in the PC01 and PC02 determination (for example, because it may incentivize PNGL to include projects in its business plan, even though they are not needed). Some indicated that there may, in principle, have been a case to incentivize capex deferrals at the time of the PC01 and PC02 determination (for example, to incentivize PNGL to seek deferrals where unexpected changes in customer demand make it efficient to do so).

1999/2000 capex deferral projects completed by the end of PC03

- 6.42 UR indicated (through its PNGL12 determination) that a capitalized financing adjustment should be made for those projects that were completed by the end of PC03. However, it did not provide any specific supporting evidence for this other than to state that the long period of deferral meant that PNGL received a relatively large benefit from the deferrals.
- 6.43 For capitalized financing relating to projects that were completed in PC03, we see little distinction between these amounts and the other amounts that were included within outperformance and discussed in Section 5. In Section 5 we have not treated capex deferrals (other than the 1999/2000 capex deferrals) differently to other categories of outperformance. For the 1999/2000 capex deferrals that were completed by the end of PC03, we consider that the situation is very similar to the non-1999/2000 deferrals (we also note that the amount of 1999/2000 capex deferrals that were completed in PC03 is very small (£0.8 million)). Therefore we do not reach different conclusions in respect of capitalized financing associated with the 1999/2000 capex deferrals that were completed by the end of PC03.
- 6.44 We think that this finding is further supported by our view that in the PC03 determination UR established a clear framework for the treatment of deferred capex that was projected to be completed in PC03. The PC03 determination foresaw that some of the 1999/2000 capex deferrals (and, for example, deferrals for infill and feeder capex from previous charge controls) would be constructed during PC03 and as a result UR reduced PNGL's capex forecasts by the deferred capex projects that were planned for PC03 (because these were already funded in 1999/2000), without signalling further adjustments once the projects were built.³⁷ We therefore think that it is appropriate to make no further adjustments for those 1999/2000 capex deferrals that were completed by the end of PC03, as the related funds have now been spent and as the PC03 determination did not foresee further adjustments to the TRV once these funds had been spent.³⁸

1999/2000 capex deferral projects not completed by the end of PC03

- 6.45 We looked at for what time period PNGL should continue to retain capitalized financing benefits for the 1999/2000 capex deferrals that were not completed by the end of PC03. We need to apply our judgement when deciding the appropriate amount of capitalized financing that PNGL should retain for the 1999/2000 capex deferrals.
- 6.46 We placed weight on UR having signalled to PNGL that it was intending to revisit the 1999/2000 capex deferrals (see paragraph 6.4) and thought that it was reasonable for PNGL to have expected that its intention was also to revisit the treatment of related capitalized financing and management fees for those 1999/2000 capex deferrals that were not completed by the end of PC03. We think that one possible conclusion of this review could be a removal of the capitalized financing for those 1999/2000 capex deferrals that were not completed by the end of PC03.
- 6.47 We consider that an appropriate time to draw a distinction is when it could be recognized that these projects were no longer relevant to the immediate investment and operational strategy. We recognize that this was not necessarily in 1999/2000. It is

³⁷ We set out in paragraph 6.23 that we thought that UR's signalling in the PC03 determination did not apply to those 1999/2000 capex deferrals that were completed in PC03.

³⁸ See, for example, Appendix D, paragraphs 157–159.

possible that PNGL was unsure when these capacity enhancements would be required, for example if this depended on the unknown future demand for gas arising from its new network developments. It may well have taken some time for this to become apparent, if it was assessed in this way. We are not aware of evidence that could help us take a view on this, although we note that in the PC03 determination, UR signalled that it would look again at these projects, suggesting that there was some awareness of an associated issue. Therefore, we consider that by 2007 it was likely to be apparent that these projects may not be required in the near future. However, we recognize that there is considerable uncertainty around the facts and what was understood at each point in time.

- 6.48 We looked at what treatment of 1999/2000 capex deferrals that were not completed by the end of PC03 was indicated when applying the existing regulatory framework for deferred capex as set out in paragraph 6.10 (as noted in paragraph 6.11 both UR and PNGL had accepted the regulatory approach to deferred capex embodied in PC03):
- (a) We thought that UR's existing regulatory approach suggests that the most appropriate treatment for the 1999/2000 capex deferrals that were not completed by the end of PC03 is to treat them in the same way as other similar capex deferrals are treated in PC03 (ie similar capex deferrals that originate in PC03).
 - (b) This new regulatory approach generally foresees that PNGL would no longer benefit from capex deferrals (ie PNGL would not retain the allowances and associated capitalized financing for capex deferrals and in some cases an adjustment would also be made for the management fee).
- 6.49 We note that the regulatory framework established in PC03 does not support an adjustment for capitalized financing that accrued before 2007, because the PC03 regulatory framework provided a forward-looking treatment for deferred capex from 2007 onwards and the 2007 determination included the capitalized financing benefit that had accrued on the 1999/2000 deferrals (and all other capex deferrals) until 2006 in the 2006 TRV. On balance, we think that it is appropriate to apply the new approach introduced in PC03 in relation to forward-looking capex deferrals to those 1999/2000 capex deferrals that have not been completed by the end of PC03.
- 6.50 Taking account of these points, we decided that the capitalized financing associated with the 1999/2000 capex deferrals that have not been completed by the end of PC03 should be removed from the 2012 TRV for the period since 1 January 2007. Applying the 2007 cut-off does not take account of the specific circumstances of each individual project, including, for example, whether PNGL has self-financed other projects instead (nor does it consider deferrals that do not fall in the 1999/2000 capex deferral category). However, we consider that it is a reasonable judgement given the limits on what can now be done to assess the efficiency of deferrals (see also paragraph 6.39 and 6.56).
- 6.51 This treatment means that PNGL retains capitalized financing for the 1999/2000 capex deferrals that have not been completed by the end of PC03 for between six and seven years (ie from 1999/2000 to the end of 2006). We note that UR submitted that other regulators often use a retention period of five years for capex outperformance and thought that the reward for the 1999/2000 capex deferrals in our determination was broadly in that range.

- 6.52 We therefore determine that the capitalized financing that had accrued since 2007 in the TRV for those 1999/2000 capex deferral projects that were not completed by the end of PC03 should be removed.³⁹
- 6.53 In its submissions, UR effectively argued that we should make further adjustments to the 1999/2000 capex deferrals for a variety of reasons. These included the following points relevant to removal of the capitalized financing sums:
- (a) a capitalized financing adjustment should also be made for the period before 2007 because this was consistent with the regulatory approach by the CC to delayed capex (as in the Heathrow Terminal 5 decision⁴⁰);
 - (b) the 1999/2000 capex deferrals were not efficient and did not benefit consumers;
 - (c) UR said that PNGL did not fulfil the conditions set in the PC01 determination of adopting its capex-related recommendations;
 - (d) UR said that removing capitalized financing that accrued before 2007 would mimic competitive outcomes;
 - (e) UR also said that removing capitalized financing for the period before 2007 was symmetric to its practice of allowing additional capex allowances for unexpected projects.
- 6.54 We do not think that UR's reasoning discloses any specific technical errors in relation of the 1999/2000 capex deferrals. The procedures followed in the inclusion of the various elements in the TRV were in accordance with the rules applying at the time. We set out our reasoning in response to each of UR's criticisms below.
- 6.55 First, we do not think that there is an obligation for a regulator always to follow regulatory precedent elsewhere (because each regulator performs its function with reference to its specific duties and circumstances and this means that a direct read across from other regulatory decisions is not possible without significant further analysis and reasoning), and so a reference to regulatory practice elsewhere does not disclose an error in its own right.
- 6.56 In relation to efficiency, we do not have the necessary evidence to allow us to assess in retrospect, many years after the event, whether the deferrals were in fact efficient. The absence of information arises in part because no efficiency test was performed. In any event UR's PC01, PC02 and PC03 determinations did not foresee an efficiency test for capex deferrals. We also note that UR had the opportunity to perform such an efficiency test in its prior determinations (or at the time of the 2006 'agreement' on the package of modifications) or could have signalled in these determinations that it would perform such an assessment for the 1999/2000 capex deferrals in the future, but chose not to do so. We do not think that not performing an efficiency test when this was not envisaged in the regulatory framework at the time constitutes a technical error. In consequence we do not have evidence to establish that the deferrals were inefficient.
- 6.57 We also do not think that UR's claim that PNGL did not fulfil the conditions that were set in the PC01 determination to improve its capex-related reporting discloses a technical error. This is because the PC01 determination did not explicitly state that

³⁹ By removing from the TRV the original allowances (as set out in paragraph 6.36), PNGL will also not earn further capitalized financing on these projects going forward.

⁴⁰ See Appendix D, paragraphs 42 & 96.

there would be any future adjustment if PNGL failed to implement the recommendations and because we think the fact that UR did not undertake such an assessment in the PC02 determination and at the time of the 2007 determination supports the view that the PC01 determination may not have envisaged a penalty for PNGL's failure to undertake the capex reporting improvements.

- 6.58 We are not persuaded by UR's argument that making an adjustment for capitalized financing accruing pre-2007 would mimic outcomes of competitive markets. UR has not stated in any of its determinations or at the time of the 2006 'agreement' that it would make adjustments to sums included in the 2006 TRV on this basis. The relevance of the competitive market as a comparator is discussed in paragraph 9.48.
- 6.59 We are not persuaded that UR's argument that making an adjustment for capitalized financing would be symmetric with its treatment of additional capex provides a reason for reaching a different judgement. Whilst a symmetric treatment of capex over and underspend may be desirable in certain instances, we do not think that symmetry of itself is an overriding principle to such an extent that the absence of its application forms an error. We note that UR has not stated in any of its determinations or at the time of the 2006 'agreement' that it made the additional capex allowances on the condition that deferred capex would be treated in a similar way.
- 6.60 UR also indicated that it considered that the absolute size of the reward PNGL received for the 1999/2000 capex deferrals was excessive. This point is equivalent to UR's reasoning that an adjustment for the 1999/2000 capex deferrals should be made because the overall charge control package for PNGL¹² is not in the public interest. We do not think that the fact that PNGL appears to have received a relatively large reward for the 1999/2000 capex deferrals is a technical error. We assess whether further adjustments to the 2012 TRV could be justified because of an overall public interest in paragraphs 9.94 to 9.109).
- 6.61 In contrast to UR's submissions, PNGL argued that making a capitalized financing adjustment would remove its future incentives for it to undertake efficient deferrals, both specifically for PNGL's operations in the existing licence area and more generally in Northern Ireland and it claimed it was retrospective.
- 6.62 We accept that not providing a capitalized financing benefit for capex deferrals may reduce PNGL's incentive to make future efficient deferrals. However, we note that PNGL's current regulatory framework also makes a capitalized financing adjustment for capex deferrals from 2007 onwards (which was not disputed by either PNGL or UR). This means that a decision to make a capitalized financing adjustment for the 1999/2000 capex deferrals from 2007 onwards provides the same incentives on PNGL as PNGL faces under the current incentives framework. We also note that PNGL will retain capitalized financing for the period until 2006 (as part of the 2006 TRV), in relation to the 1999/2000 capex deferrals that were not completed by the end of PC03.
- 6.63 We do not think that removing the capitalized financing benefit from 2007 onwards is likely to be perceived as retrospective because UR had sufficiently signalled in its PC03 determination that it would review the treatment of the 1999/2000 capex deferrals (see paragraph 6.4).

Management fee

- 6.64 We set out below our assessment of the appropriate treatment of the management fee related to the 1999/2000 capex referrals.

1999/2000 capex deferral projects not completed by the end of PC03

- 6.65 In respect of the management fee for those 1999/2000 capex deferrals that have not been completed by the end of PC03, we think that an adjustment should be made if it is likely that PNGL would have been able to avoid payment of a proportion of the management fee by not completing the 1999/2000 capex deferrals and as such the management fee could be considered an integral part of the 1999/2000 capex deferral projects. We note that PNGL stated that the management fee was 'largely' fixed. While PNGL argued that this meant the management fee adjustment should be zero, we consider it implies that there may be some variable elements to the management fee. We also note that PNGL's statements indicated that including the management fee in the project costs would make them more comparable to capital costs of other organizations.⁴¹
- 6.66 We note that UR's PC01 determination stated that 49 per cent of the management fee was variable. PNGL suggested that this was an inaccurate estimate.⁴² However, we consider that the PC01 determination forms part of the regulatory framework applying to the 1999/2000 capex deferrals, and we did not think that PNGL's statements provided sufficient evidence that the assumption in the PC01 determination were inappropriate.
- 6.67 The evidence from PNGL and UR indicated that the variable element of the management fee in PC01 was around 5 per cent of the capex allowances in PC01.⁴³ We therefore include a management fee uplift of 5 per cent to the 1999/2000 capex deferral projects (for those projects that were not completed by the end of PC03).
- 6.68 We also note that PNGL stated that it still planned to deliver the vast majority of all the 1999/2000 capex deferral projects.⁴⁴ We think that PNGL will receive an allowance for the management fee associated with the 1999/2000 capex deferrals when it applies for funding for these projects in the future. It appears to us that there is therefore a risk that without an adjustment for the variable element of the management fee PNGL will retain funding for the variable element of the management fee when the deferral was made and would receive further funding for the variable element of the management fee when the projects will be delivered and as such there is a risk of PNGL being funded twice for the variable element of the management fee for the 1999/2000 capex deferrals that are still to be completed. We thought that this further supported our decision to make an adjustment for the management fee.
- 6.69 UR indicated (through its PNGL12 determination) that a management fee adjustment of 20 per cent should be made. However, we did not find sufficient supporting evidence for this assumption. In order to use this assumption we would have needed to conclude that a large majority of the management fee is variable. We accepted PNGL's argument that a significant proportion of the management fee was fixed because UR's determinations indicated that UR also considered that a significant proportion of the management fee was fixed (eg the PC01 determination assumed that 51 per cent of the management fee was fixed).

1999/2000 capex deferral projects completed by the end of PC03

- 6.70 Neither UR nor PNGL suggested that the management fee related to the 1999/2000 capex deferral projects that have been completed in PC03 should be removed from

⁴¹ See Appendix D, paragraphs 45 & 47.

⁴² See Appendix D, paragraphs 49 & 50.

⁴³ Appendix D, paragraphs 77 & 120.

⁴⁴ See UR PC03 determination, paragraph 6.3 and UR [PNGL12 determination](#), Annex 4.

the TRV. We think that it is not against the public interest that the management fee related to the original capex allowances relating to those 1999/2000 capex deferrals that had been completed by the end of PC03 should be retained in the TRV as the management fee (at least to the extent that it is variable) can be considered to be an integral part of PNGL's capex projects and as such is part of the investment by PNGL in the gas distribution network.

Conclusion

- 6.71 In summary we think that the following treatment of the 1999/2000 capex deferrals is appropriate:
- (a) For those 1999/2000 capex deferrals that were completed in PC03, we do not find these to be against the public interest and so no further adjustments are made.
 - (b) For those 1999/2000 capex deferrals that were not completed in PC03, we find these to be against the public interest and so the original sums relating to these projects should be removed from the TRV including the capitalized financing benefit that accrued to PNGL since 2007, uplifted by a 5 per cent management fee adjustment.
- 6.72 In making these changes we removed £8.6 million (in 2010 prices) from the 2012 opening TRV.

7. Rate of return for PNGL

Introduction

- 7.1 This section sets out our assessment of the allowed rate of return for PNGL in the context of its price control determination for the period 2012/13.¹
- 7.2 A fixed real pre-tax rate of return of 7.5 per cent was allowed for 2006 to 2016 as part of the 2007 determination.² Prior to this, PNGL had a fixed real pre-tax rate of return of 8.5 per cent for the period 1996–2016. UR has explained the context for the award of this fixed 8.5 per cent rate of return as follows:³
- (a) In 1996, PNGL was awarded a licence that gave it a recovery period of 20 years, during which time the company would construct the network, develop and grow the market and ultimately recover its investment.
 - (b) The original licence differed from a typical regulated entity’s licence in that all of PNGL’s expenditure was capitalized, regardless of its nature (ie both opex and capex capitalized). Capitalizing all of PNGL’s expenditure was considered necessary because it was private sector funding developing the network from the outset, with no meaningful income generation expected to follow for several years (since it would take time to grow the market). Therefore it was considered reasonable that all expenditure be capitalized.
 - (c) In addition, PNGL was granted a rate of return in the licence of 8.5 per cent, in real terms and pre-tax, and stated as fixed until the end of the licence recovery period. The high rate of return was granted to reflect the high level of risks associated with developing an entirely new market from a zero base.
- 7.3 PNGL submitted that the fixed rate of return allowed for the period 1996 to 2016 was a core part of attracting the original investment in Northern Ireland as it was necessary for a greenfield investment to have a relatively long-term framework to provide certainty to investors.
- 7.4 As part of the 2007 determination, the fixed 8.5 per cent rate of return was reduced by 1 per cent. PNGL was allowed under its revised licence to earn a real pre-tax rate of return of 7.5 per cent until 2016. The rate of return to be applied from 2017 was to be determined by UR in the price control review that covered this period.⁴
- 7.5 Although UR’s final price control decision for 2012/13 upheld the allowed rate of return of 7.5 per cent,⁵ UR submitted to us that the current WACC for PNGL was significantly lower than the allowed rate of return and invited us to revisit it.⁶
- 7.6 PNGL submitted that a 7.5 per cent rate of return through to 2016 was appropriate, as it reflected the terms of the 2006 ‘agreement’ on the package of modifications, and the clear intention at that point was that the average rate of return set was to prevail

¹ In this section, we distinguish between the WACC that refers to the cost of capital which compensates for systematic risks, and the allowed rate of return which may include compensation for project-specific risks (see paragraphs 7.29–7.36) in the context of a greenfield investment.

² UR [initial submission](#), paragraph 3.32.

³ UR, [Phoenix Natural Gas Limited Price Control Review 2012–2013: Final Decisions](#), January 2012, UR 13.1, Appendix 1, p80.

⁴ PNGL [statement of case](#), Annex 2, p13.

⁵ UR, [Phoenix Natural Gas Limited Price Control Review 2012–2013: Final Decisions](#), January 2012, UR 13.1, paragraph 7.28.

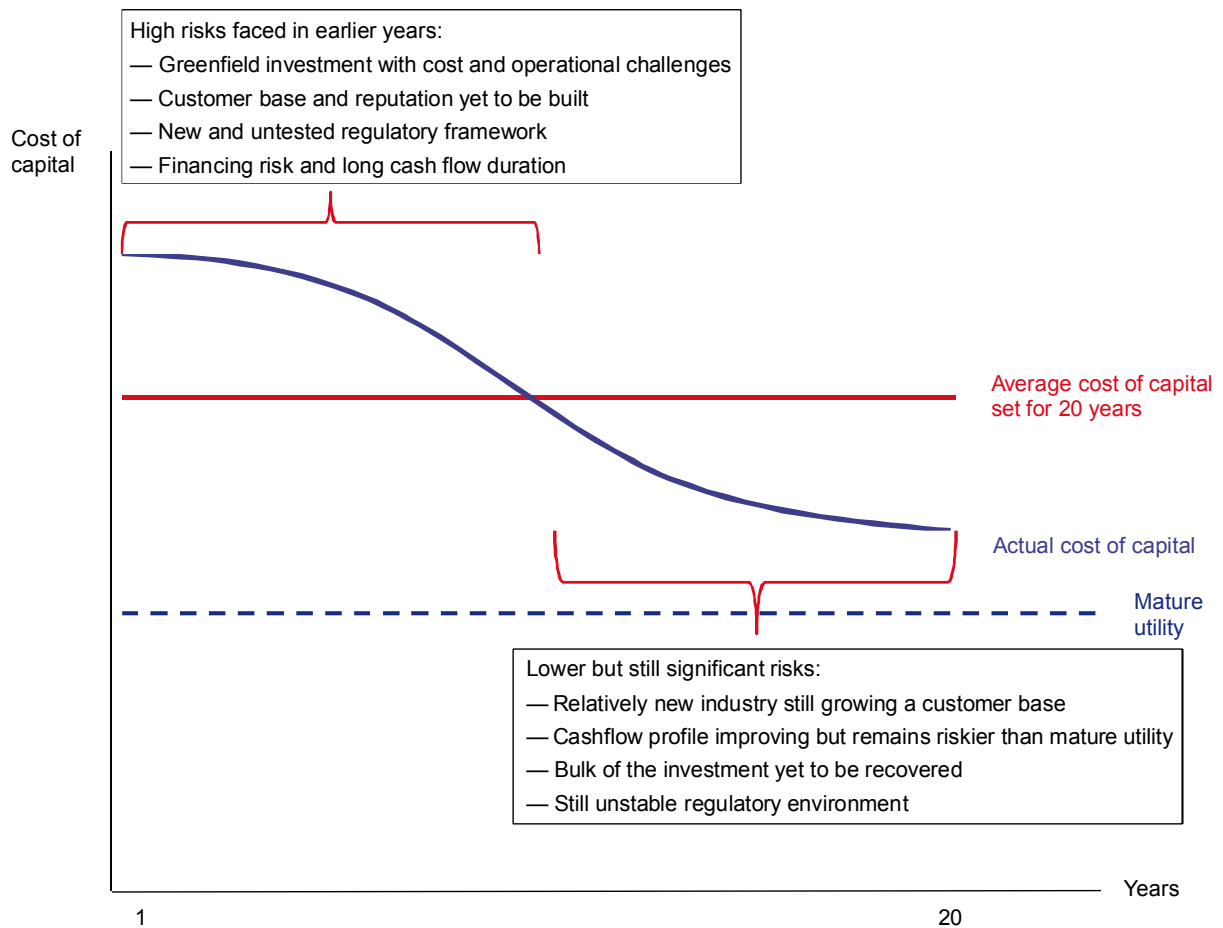
⁶ UR’s current estimate of the WACC for PNGL is 5.1–5.5 per cent; in its ‘Introduction to the Reference’, UR states: ‘we welcome the scrutiny that we anticipate the Commission will now wish to give ... particularly to the proposed cost of capital allowance.’—see UR [initial submission](#), paragraph 1.25, p7.

until 2016. PNGL submitted that a detailed investigation of the current WACC was not a relevant calculation⁷ as:

- (a) The 7.5 per cent rate of return was agreed and fixed up to 2016.⁸
- (b) The allowed return (for 2012 and 2013) should represent the average risk over the 20-year period since 1996. The fixed rate of return set in 1996, and subsequently reset in 2006, represented a rate of return based on average risk while actual risk would have changed over the period. PNGL stated that it would be opportunistic to readjust returns (for the next price control) based on actual risk for the last five years of the period.⁹ Graphically, the latter assertion by PNGL is shown in Figure 7.1. PNGL considers that 're-setting the WACC now would require the company to also be compensated for the high up-front risks relative to the allowed WACC'.

FIGURE 7.1

Actual and average cost of capital over the life cycle of a greenfield investment



Source: PNGL response, p93.

⁷ PNGL response, paragraph 3.27, p98.

⁸ PNGL response, paragraph 3.1, p90.

⁹ PNGL response, paragraph 3.2, p90.

- 7.7 Some third-party submissions have cited concern that the allowed rate of return for PNGL appears to be excessive. Notably, CCNI stated:¹⁰

According to the Regulator's analysis PNG has been significantly de-risked and the company requires no further growth to recover its investment by 2046. We believe that the Regulator should therefore examine the Rate of Return it allows PNG and consider it against the rate Ofgem allows of 5.86 per cent....

The Regulator has stated that PNG is rewarded with the highest Rate of Return of any comparable regulated utility in the UK ... PNG has a Regulatory Rate of Return of 7.5 per cent against that of GB Gas Distribution companies of 5.8 per cent. The cost this allowed Rate of Return generates when applied to the Total Regulatory Value (TRV) is one that must be paid by consumers. As we already outlined, these are the same NI consumers who currently have the highest energy costs in the UK and are more likely to be in fuel poverty.

Our view

- 7.8 We note that it is unusual, in a regulatory price control setting, for a rate of return to be fixed for 10 or 20 years and to span more than one price control period. We are not aware of any similar arrangements in other regulated sectors in Great Britain.¹¹ Most Great Britain regulators adjust the cost of capital at each price control review on a periodic (eg five-yearly) basis. Ofgem has recently proposed a move to an eight-year price control period and has adopted an indexation mechanism for the cost of debt to deal with interest rate movements within the period.¹² We note that the 20- and 10-year arrangements between UR and PNGL had no such adjustment mechanisms.
- 7.9 However, we consider that the unusual nature of the 1996 regulatory arrangement reflected the unique greenfield nature of PNGL's investment in Northern Ireland at the time.
- 7.10 We have seen no evidence that the allowed rates of return in 1996 and in 2006 were estimated on a detailed, bottom-up basis. No contemporaneous documentation is available to explain the calculations made. We infer from these statements that no bottom-up estimation of the 8.5 and 7.5 per cent rates of return had been undertaken at the time that they were set, and that they appeared to have been reached by negotiation:

(a) UR noted that:

PNGL's original rate of return was set at 8.5 per cent in 1996. As part of the 2007 licence determination the rate of return was reduced to 7.5 per cent, with the one per cent reduction determined as part of the overall licence package. In the absence of a detailed build-up of the typical components that constitute the cost of capital, it is difficult to set out precisely the balance between risks and returns.

¹⁰ CCNI [initial submission](#), pp13&14.

¹¹ PNGL submitted that this was not necessarily an unusual feature of the regulatory landscape in Northern Ireland where the firmus energy licence also allowed a fixed rate of return across more than one price control period.

¹² For example, see Ofgem, '[Decision on strategy for the next gas distribution price control-RIIO-GD1](#)', 31 March 2012, pp3&47.

(b) Similarly, PNGL noted that:

The allowed WACC was agreed for 20 years in 1996, and was revised downwards by 1% as part of the package of measures forming the 2006 Agreement but even then remained fixed until 2016. As a result, a standard full CAPM analysis has not been carried out at either of the price control reviews following the 2006 Agreement (ie PC03 and PNGL12).

7.11 We sought to understand the basis for the 7.5 per cent rate of return that had been written into the licence in 2007, which in turn necessitated an understanding of the 8.5 per cent that was originally granted in 1996. Given the lack of contemporaneous evidence clarifying the calculation of the allowed rates of return for 1996 and 2006, we first consider evidence which could provide an 'ex post rationalization' of the appropriateness of the 8.5 and 7.5 per cent rates of return respectively. We then consider the appropriate rate of return for the current price control period, ie 2012 and 2013.

Rate of return in 1996

7.12 In 1996, PNGL was awarded a licence that gave it a recovery period of 20 years, during which time the company would construct the network, develop and grow the market, and recover its investment through regulated charges. PNGL was granted a rate of return of 8.5 per cent, in real terms and pre-tax, which was stated as fixed until the end of the licence recovery period.¹³

7.13 The parties agreed that this rate of return reflected a high level of risk faced by PNGL at the time of initial investment:

(a) UR stated that this 'high rate of return was granted to reflect the high level of risks associated with developing an entirely new market from a zero base'.¹⁴

(b) PNGL stated that under the 1996 licence, its rate of return was fixed at 8.5 per cent over the 20-year recovery period from 1996 to 2016. The rate of return was set at this level in order to attract the investment to start Northern Ireland's natural gas industry. PNGL also noted that the profile of risks that PNGL faced was loaded towards the front end of the period.¹⁵

7.14 We note the views of the two parties regarding what the 8.5 per cent allowed rate of return in 1996 represented:

(a) PNGL argued that the 8.5 per cent represented a rate of return which reflected the average risk of its greenfield investment over 20 years:

an 8.5% real pre-tax return on cashflows over 20 years to reflect the expected average level of risk the company would face over that timeframe and to encourage investors to finance the scale of investment required for this project, given the profile of revenue recovery

¹³ UR, [Phoenix Natural Gas Limited Price Control Review 2012-2013: Final Decisions](#), January 2012, UR 13.1, Appendix 1, p80.

¹⁴ *ibid*, p80.

¹⁵ PNGL [statement of case](#), paragraphs 5.43 & 5.44, p63.

and inherent commercial risks (for the first ten years of the investment, 100% of the investment was underwritten by equity investment).¹⁶

- (b) UR argued that it represented a risk premium over the return to mature utilities to reflect the risks of PNGL's greenfield investment:

This 8.5% figure compared to the 7.0% real, pre-tax rate of return that was offered by Ofgas to Transco as the owner of the more mature GB gas distribution network in a price control that came into force in 1997.... Although there is no document that we are aware of that puts these two decisions side-by-side in the way that we are doing, we think it is reasonable to say that in 1996 we allowed PNGL a 1.5 percentage point 'risk premium' to reflect the higher risks of its business model.

- 7.15 In response to a comparison between the rate of return for PNGL and other Great Britain regulated utilities, PNGL argued:

- (a) There was no like-for-like comparator for PNGL¹⁷ and the headline cost of capital must always be considered in light of the overall package of risk and return incorporated in the price control, as well as the financial and operating environment of the company.
- (b) The allowed rate of return of 8.5 per cent was not out of line with evidence from other rate of return determinations leading up to the 1996 licence. For example, PNGL argued that the government discount rate in 1996 for investment by public corporations was 8 per cent.¹⁸ PNGL also cited evidence from various regulatory decisions between 1991 and 1995 to justify a range for the WACC of 7–10 per cent. Specifically, PNGL cited the following decisions on the real pre-tax WACC: BAA (1991, 8 per cent); British Gas (1993, 6.5–7.5 per cent); RECs Distribution (1994/95, 7 per cent); Scottish Hydro-Electric (1995, 7 per cent); Ofwat on water (1994, glidepath from 13 to 6–7 per cent on post-tax basis); MMC on water (1995, 6–8 per cent).¹⁹

Our view

- 7.16 We note that PNGL's headline rate of return was approximately 1.5 per cent higher than contemporaneous WACC determinations for mature Great Britain energy utilities in 1995/96, as shown in Figure 7.2 below.²⁰ We note that this differential is also broadly consistent with the evidence presented by PNGL.²¹
- 7.17 However, we note that the figures shown in Figure 7.2 may be affected by differences in the level of gearing. A lower level of risk enables a company to have a relatively higher level of gearing and hence reduce its tax bill due to the tax shield on

¹⁶ PNGL, [statement of case](#), paragraph 2.17, p22.

¹⁷ PNGL [response](#), paragraphs 2.2 & 2.3, p83.

¹⁸ This is guidance by HM Treasury on the rate of return for investments by public corporations. See PNGL [response](#), paragraphs 2.5 & 2.6, p84.

¹⁹ PNGL [response](#), Annex 6, Table 1.

²⁰ We note that in the 1990s, many Great Britain regulators included an allowance for a 'small company premium'. If this had been allowed for PNGL in 1996, it would reduce the indicative difference in the headline rate of return in Figure 7.2.

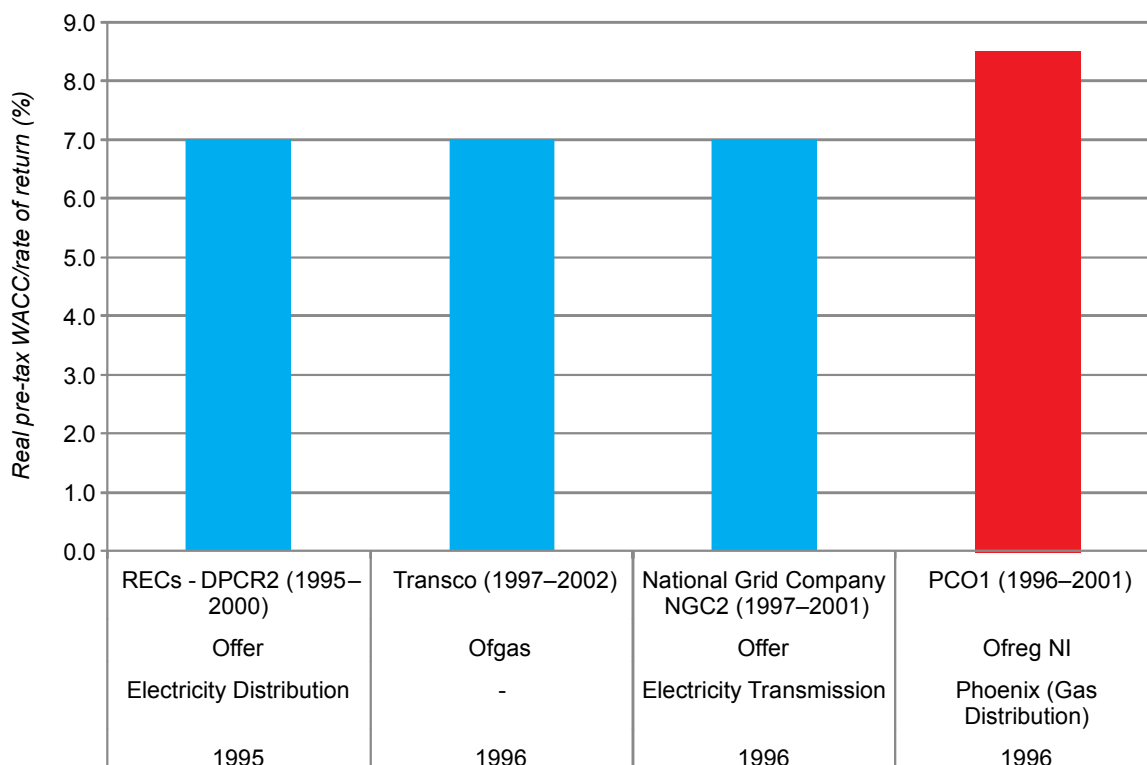
²¹ We have assessed that the evidence presented by PNGL in Annex 6, Table 1, is consistent with a range of 6–8 per cent. We have not considered that this evidence is consistent with the 7–10 per cent range asserted by PNGL; this is because the upper end of PNGL's range appears to be informed by a post-tax range for expected profitability in the water sector which was set to decline from 13 to 6–7 per cent, while the required return to finance new investment was 5–6 per cent (see Ofwat, '[Future Charges for Water and Sewerage Services](#)', 1994, pp48&52). We note also that the MMC (1995) decision cited by PNGL for the water sector gives a pre-tax range of 6–8 per cent. See PNGL [response](#), Annex 6, Table 1.

debt. Great Britain energy utility WACCs were typically calculated on the basis of around 50 to 60 per cent debt in the capital structure, whereas PNGL was entirely equity funded at this time.

- 7.18 For illustration, a crude approximation of the value of the tax shield of debt within the WACC allowed to mature utilities in Figure 7.2 is potentially as much as 1 per cent.²² This may partly explain the impact of lower risk on the observed differential between the headline rate of return for PNGL and the WACC for mature utilities.

FIGURE 7.2

Allowed rate of return for PNGL in PC01 relative to WACC for other Great Britain energy utilities



Source: CC and Oxera analysis based on various regulatory documents.

- 7.19 We have sought to understand the main risks faced by PNGL in 1996. As noted in the introduction, given the lack of contemporaneous documentation, this is by necessity an ex-post rationalization.
- 7.20 It is difficult to form an accurate impression of the level of risk faced by PNGL in 1996 due to the time elapsed and the lack of contemporaneous documentation. We based our assessment on our understanding of the arrangements in 1996 and the submissions on this subject from PNGL and UR regarding the company's initial investment. The statements are set out in detail in Appendix D.
- 7.21 In the following paragraphs we set out our views on what we perceive to be the main categories of risk facing PNGL in 1996, including risks posed by the greenfield nature of the investment, the size of the capex programme, the regulatory framework, and

²² ie with simple assumptions of a nominal allowed cost of debt of about 6 per cent, a tax rate of about 30 per cent, and gearing of about 55 per cent, the value of the tax shield is potentially as much as (6 per cent * 0.3 * 0.55) = 1 per cent.

political risks. We then consider whether these risks, in combination, could justify the allowed rate of return of 8.5 per cent for the period 1996 to 2016.

Risks posed by the greenfield nature of the investment and the size of the capex programme

- 7.22 First, we note that at the time of initial investment PNGL was exposed to considerable volume risk:
- (a) As PNGL was building its customer base from zero, it faced significant uncertainty regarding the uptake of gas connections.
 - (b) Once customers were connected, PNGL would still face some uncertainty regarding the level of gas consumed. Given that the company was acquiring a customer base from zero, it would have been difficult to forecast the extent to which consumers would use gas appliances.
 - (c) We note that volume risk can be mitigated by the form of the price control regime; however, PNGL was exposed to volume risk because of the form of price cap regulation in its original licence.²³
- 7.23 In contrast, Great Britain operators would not have faced significant volume risk because they had an established customer base which was connected to the network and whose consumption patterns were well understood. For these reasons, we consider that PNGL was exposed to significantly higher volume risk than mature Great Britain utilities.
- 7.24 We now turn to the risks posed by the size of the construction programme facing PNGL in 1996. At this time, there was no gas network in the licence area and PNGL's business plan was to build a network from scratch. This means that the capex programme dominated the activities of PNGL in its early years; we consider that PNGL was likely to have been exposed to a relatively high degree of construction risk. By this, we mean that there was a risk that capex projects were not successful or were not achievable within the budget or timescale allowed. Although any Great Britain utility with an ongoing capex programme may be exposed to a degree of construction risk, this risk can generally be managed alongside the existing, established business.
- 7.25 A further implication of the greenfield nature of PNGL's investment, with a zero customer base at the onset, was that PNGL could not generate revenues in the early years of investment to cover its capex and opex outlays. This necessitated a deferral of revenue recovery to later years of the licence.
- 7.26 Further, the 1996 regulatory regime required PNGL to recover all its investment within 20 years. This represented a short period to recover investment made in the earlier years, and investments made in later years would have to be recovered over a potentially very short time horizon. As a consequence, prices had to be set at a high level in order to recover the costs over 20 years and this increased the risk of under-recovery.

²³ UR, [Phoenix Natural Gas Limited Price Control Review 2012–2013: Final Decisions](#), January 2012, UR 13.1, Appendix 1, p81. UR stated that the move from price control to revenue control regulation removed volume risk as part of PC03—it is implicit that PNGL was exposed to volume risk in its original licence. Nonetheless, we note that volume risk was limited due to a periodic review process and a reopener, in the 1996 licence, for volume underperformance of greater than 15 per cent. This price control reopener applied between 1996 and 2001.

Regulatory and political risk

- 7.27 We next considered whether PNGL faced a relatively high degree of regulatory risk in 1996. In this context, we note that the regulator was established in 1996, at the same time as PNGL, and therefore had no track record. In our view, the lack of track record compared with Great Britain regulation may have given rise to a degree of uncertainty as to the future regulatory environment that PNGL might face.
- 7.28 We also considered PNGL's statement that the initial investment in 1996 was undertaken at a time of considerable social and political uncertainty in Northern Ireland.²⁴ Since the original licence pre-dated the Good Friday accord, it seems reasonable to consider that investments in Northern Ireland would have carried higher risk in 1996 than similar investments in Great Britain.
- 7.29 Therefore, we consider that PNGL faced non-trivial project-specific risks in 1996, as a result of the greenfield nature of the investment, the newness of the regulator, the nature of the regime, and the political climate in Northern Ireland at the time, that collectively meant that PNGL, having invested considerable sums in building and running the network in its initial years, might fail to recover the full value of its investments over the 20-year period initially contemplated in the licence.
- 7.30 We note these risks may be cumulative: in particular, the risk posed by revenue being deferred into the future is likely to be heightened by uncertainty about the future regulatory and political regime.
- 7.31 We consider that it is not necessary that there would have had to have been a complete failure of demand in order for these risks to materialize and for PNGL to fail to generate sufficient revenues to compensate for the sunk costs of initial investment and operation within the licence recovery period.
- 7.32 Given our assessment of risks in the preceding paragraphs, it appears likely that the project-specific risks faced by PNGL in 1996 were high. Specifically, PNGL had significant volume risk exposure due to the uncertainty of gas connections uptake and usage. At the same time, PNGL's original licence envisaged the recovery of high upfront capex and opex towards the end of a 20-year period with a risk of under-recovery due to the uncertain demand for gas connections.²⁵
- 7.33 In the specific context of regulation of a greenfield infrastructure asset, these project-specific risks may require compensation. This is because if greenfield utility investors are exposed to asymmetry due to capped upside returns but unlimited downside returns due to project risks, they will refrain from investing unless they receive a return over and above the WACC. This premium may justify an allowed rate of return above the WACC. A stylized illustration of asymmetric risk is included in Appendix F.
- 7.34 Further, in addition to project-specific risks, we consider that PNGL was likely to have faced a high WACC in its initial years, most notably due to increased volume risk. In particular, we thought that connections could be sensitive to economic conditions. We consider that as the network matured over time, the forward- looking WACC was likely to reduce.

²⁴ PNGL [statement of case](#), paragraph 5.52, p65.

²⁵ PNGL noted that there was some disagreement over whether the company would have been allowed to recover the residual value of under-recoveries at the end of the 20-year agreement, under the 1996 licence. See PNGL [response](#), paragraphs 5.12–5.15, pp17&18.

- 7.35 In order to make the investment in 1996, we consider that PNGL would have required compensation for systematic risks such as would be reflected in the WACC and project-specific risks.
- 7.36 In this light, we consider that there was justification for setting at 20-year fixed rate of return at the outset of the investment programme in 1996, because it gave PNGL a commitment that investment would be rewarded at a rate of return above the forward-looking WACC for a fixed period of time in return for assuming the high upfront risks associated with the project. In the absence of contemporaneous documentation, including business plans and investment appraisals quantifying the risks faced at the time, we cannot, in 2012, calibrate the numbers with any precision.
- 7.37 We considered PNGL's argument (illustrated in Figure 7.1) that the 8.5 per cent represented an average return over the 20-year period in which risk was higher at the start of the period than at the end, but in which compensation for risk was spread evenly.²⁶ PNGL told us that the rate was just such an average and that it would be opportunistic to adjust returns based on actual risk. UR told us that whilst it could see that this kind of declining risk profile applied to certain categories of risk such as that associated with capital expenditure, the fundamental risk facing PNGL was that of under-recovery and this risk increased as the end of the recovery period, 2016, drew nearer. Our appraisal of the facts suggests to us that the uncertainty facing PNGL, and hence the risks, were likely to be higher at the time of the initial investment and were likely to moderate over time as events unfolded and the uncertainties were resolved. Whilst we accept that as 2016 drew closer PNGL would have more information on which to judge the extent to which it might recover its investments, we viewed this as a resolution of uncertainty rather than indicative of higher risk. While this matter is not free from doubt, it seems most likely to us that the rate set in 1996 represented an average and that PNGL was undercompensated for risks in the early years of network development.
- 7.38 Finally, we have also considered the nature of the 1996 licence. We note some similarity between the 20-year rate of return allowance in 1996 and long-term infrastructure contracts such as private finance initiatives (PFIs) or public private partnerships (PPPs). We note that HM Treasury and Infrastructure UK have indicated that RAB-WACC models typically require 0.25 to 3.0 per cent higher than publicly funded infrastructure projects, while the risk-reward arrangement conferred by a PPP/PFI-type deal usually requires around 2 to 3.75 per cent higher than a publicly funded infrastructure project.²⁷ We have considered that, in analogy, this may also be a contributing factor in the justification of a higher rate of return for PNGL in 1996 relative to other Great Britain utilities.

Rate of return in set as part of the 2007 determination

- 7.39 As part of the 2007 determination, the fixed 8.5 per cent rate of return from the earlier licence was reduced by 1 per cent. PNGL was allowed under its revised licence to earn a real pre-tax rate of return of 7.5 per cent until 2016. At the same time, the recovery period was extended to 2046, and a number of other significant changes

²⁶ We also note PNGL's statement that other greenfield network utilities have been allowed a high WACC in early years of investment relative to mature utilities, with this WACC declining over time. PNGL suggested that the mobile phone industry was an example of this—for mobile call termination charges the WACC had declined from 13.1 per cent in 1998 (MMC decision) to 6.2 per cent in 2011 (Ofcom decision). PNGL acknowledged that the cost of capital in the mobile sector was not directly analogous, eg there had been competing network providers and the mobile sector had generally not been subject to economic regulation in the same manner as a network utility. Nonetheless, this appears to be relevant as an example of a sector where the risks in early years were recognized in decisions on the WACC. See PNGL [response](#), pp96&97.

²⁷ HM Treasury and Infrastructure UK (2010), [National Infrastructure Plan 2010](#), p45.

were made to the regulatory framework. These changes are discussed in further detail in Section 2.

- 7.40 UR argued that the reduction in the allowed rate of return from 8.5 to 7.5 per cent reflected the new risk arrangement introduced by the 2007 determination.
- 7.41 On the other hand, PNGL argued that the reduction in the rate of return in 2006 was not due to a de-risking of its business, but as part of an ‘overall sharing of value’ embedded in the 2006 ‘agreement’ on the package of modifications. PNGL clarified that while a standard full CAPM analysis had not been carried out at either of the price controls following the 2006 ‘agreement’, the 7.5 per cent allowed rate of return reflected both compensation for the high upfront risks faced by PNGL early in the 20-year period and a risk premium which PNGL continued to face relative to a more mature network utility.
- 7.42 We note that the 7.5 per cent rate of return is not easily decoupled from its 8.5 per cent predecessor—as set out in paragraph 7.10, both UR and PNGL allude to a reduction from 8.5 to 7.5 per cent, implying that there is some implicit reliance of the 7.5 per cent rate of return on the 8.5 per cent rate which was originally allowed in 1996.

Our view

- 7.43 As set out in the introduction, there is no bottom-up, detailed analysis to substantiate the 7.5 per cent rate of return. Thus, we sought to understand the rationale for the allowed rate of return as per the 2007 determination on an ‘ex post’ basis.
- 7.44 In doing so, we first considered the risk profile of PNGL in 2007. This had changed markedly since 1996 for three principle reasons: first, the new regulatory arrangements introduced as part of the 2007 determination, secondly due to the maturity of the business, and thirdly due to improvements in the political climate. We discuss these factors in turn below.
- 7.45 We then consider the appropriateness of the 7.5 per cent rate of return. In doing so, we take into account the risks faced by PNGL in 2007 and how these compared with Great Britain utility comparators. However, we do not focus solely on the risks faced by PNGL in 2007; we also consider whether it remained appropriate to take some account of the risks faced by PNGL in 1996; in particular, by continuing to allow a premium for project-specific risk in the 2007 rate of return.
- 7.46 For simplicity, throughout this section we refer to features of the 2007 determination. However, we are aware that there are timing issues, whereby some changes in the regime for PNGL were implemented via licence modifications in 2007 and 2009, while others were introduced as elements of the price control determination for PC03 (ie 2007–2011).

Changes to the risk profile of PNGL due to the regulatory framework introduced in 2007

- 7.47 We consider the impact of the following mechanisms, introduced as changes to the regulatory framework as part of the PC03 determination in 2007, on the risk profile of PNGL:
- (a) the extension of the recovery period and profiling adjustment;

- (b) the introduction of a regulatory asset base;
- (c) the retrospective adjustment mechanism for opex and capex allowances; and
- (d) the move from a price cap to a revenue cap

7.48 We then consider the evidence cited by UR that PC03 was a regulatory rescue for PNGL.

The extension of the recovery period and profiling adjustment

7.49 A key part of the 2007 determination was the extension of the recovery period from 20 years to 50 years; and the introduction of a Profile Adjustment which allowed revenue recovery to be profiled in line with the expected growth in volumes over the remaining 40-year period.²⁸ We note PNGL's argument that this mechanism significantly lengthened the time before PNGL's shareholders would be able to recover their initial investment.²⁹ However, notwithstanding PNGL's point, we consider that the extension of the recovery period reduced PNGL's risk as it permitted it to recover its investments over a significantly longer timer period than had previously been envisaged.

The introduction of a regulatory asset base

7.50 As part of the 2007 determination, there was a move towards RAB-based regulation for PNGL:

- (a) UR argued that the move to the more conventional RAB-based regulatory model significantly altered the risk profile of the PNGL business.
- (b) PNGL argued that there was nothing inherent in a RAB which would make the company less risky. However, it noted that the RAB-based model benefited PNGL because it was a construct with which investors and ratings agencies were more familiar, thereby reversing a disadvantage faced by PNGL compared with Great Britain utilities in accessing debt markets, and in facilitating possible expansion of PNGL's licence area.

7.51 We consider that the move towards a conventional RAB-based model represented a reduction in risk for PNGL relative to 1996:

- (a) In the first instance, the RAB-based model is well understood, and provides certainty and protection for investors. As HM Treasury noted, this model 'has a proven track record in enabling increased investment and offering certainty to investors, thereby lowering the cost of capital'.³⁰
- (b) In the second instance, the move to a familiar model would have been a positive signal of the company's increasing maturity—since, by 2006, the company had constructed much of its network, it could be regulated using a similar model to that used in Great Britain, albeit with some features to accommodate its relative immaturity, such as the Profile Adjustment which continued to delay PNGL's revenue recovery into later years of the licence. Therefore the move towards RAB-based regulation was a positive signal of the company's increasing maturity.

²⁸ PNGL [statement of case](#), Annex 5, p5.

²⁹ PNGL, [statement of case](#), Annex 5, p5.

³⁰ HM Treasury and Infrastructure UK (2011), [National Infrastructure Plan 2011](#), p101.

The retrospective adjustment mechanism for opex and capex allowances

7.52 As part of the 2007 price control, a 'retrospective adjustment mechanism' was introduced:

(a) UR argued that the introduction of this mechanism saw PNGL's allowances, for both opex and capex, adjusted up or down depending on out-turn events, which significantly reduced activity-based risks for PNGL.³¹

(b) PNGL argued that the retrospective mechanism did not reduce risk; in particular, it argued that there was a de minimis threshold for an adjustment in response to overspend, while the ability to outperform was reduced by prospective adjustments for underspend. PNGL argued that the 'potential upside is therefore reduced, while the potential for downside is exacerbated'.

7.53 We note the similarity between the retrospective adjustment mechanism introduced by UR and mechanisms for uncertainty mitigation in other regulated sectors in Great Britain (eg logging up or down of capex in the water sector).³²

7.54 In general, these mechanisms are perceived by investors, ratings agencies and regulators as limiting risk for regulated companies.

The move from a price cap to a revenue cap.

7.55 In PC03 PNGL was moved from a price cap to a revenue cap:

(a) UR argued that this reduced the risk exposure of PNGL; UR stated that a revenue cap shifted volume risk to consumers and provided a level of revenue security with regard to allowed expenditure undertaken by PNGL.

(b) PNGL argued that any impact on risk of reducing the volume driver was likely to have been small, and should have been offset by the introduction of a revenue driver based on a connections incentive. PNGL argued that UR stated at the time of the move to the revenue cap regime that the connections incentive would expose PNGL to a similar level of volume risk as in the preceding price cap regime.

7.56 We consider that a revenue cap tends to provide lower-volume risk exposure than a price cap regime. However, we are mindful that a high proportion of volume-based variable entitlement within a revenue cap regime would increase exposure to volume risk.

7.57 There does not seem to have been much clarity at the time of the 2007 determination regarding the impact that the connections revenue driver would have. This is because it had not yet been designed; the intent, however, appears to have been to maintain a similar exposure to volume risk as in the preceding price cap regime. Specifically, in the PC03 Determination UR noted:

We also intend to introduce an incentive regime for connections and will consult in 2008 on how this should be designed. In designing an incentive regime we are minded to take into account current connection projections and marketing and incentive allowances in determining an

³¹ UR, [Phoenix Natural Gas Limited Price Control Review 2012-2013: Final Decisions](#), January 2012, UR 13.1, Appendix 1, p81.

³² For example, see Ofwat (2009), [Future water and sewerage charges 2010-15: final determinations](#), p119.

appropriate connections target with the reward or penalty increasing depending on how far PNG are from the target. The regime will reflect a similar risk to the volume risk currently faced by PNG.

- 7.58 With the benefit of hindsight we consider that the revenue driver introduced in PC03 did not expose PNGL to a high degree of volume risk. Under the preceding price cap regime, PNGL was at risk of demand fluctuations across its whole customer base. On the other hand, under the revenue cap regime, the connections revenue driver was based on a relatively limited target to connect owner-occupier households to the gas network. In terms of magnitude, UR told us that volume underperformance produced a negative impact of over £9 million for PNGL in 2006 while the connections incentive introduced in PC03 had a much smaller revenue impact of £10,000 in 2009.
- 7.59 Therefore, on an out-turn basis, the move to a revenue cap regime considerably reduced PNGL's exposure to volume risk.
- 7.60 However, this may not have been known and fully understood at the time of the 2007 determination, given UR's stated intent that the move to the revenue cap regime would lead to equivalent volume risk exposure for the company due to a connections revenue driver.

Interpretation of data on market to asset ratios

- 7.61 We note that there is a disagreement between the two parties regarding the extent to which the 2007 determination should be perceived as a regulatory 'rescue' for PNGL. UR told us that there was clear evidence of a rescue because PNGL's MAR increased from 74 per cent in 2004 to 125–130 per cent in 2007 and remains at about 1.25 currently. PNGL said that the 74 per cent estimate of the MAR in 2004 has no basis because the opening asset value for PNGL's RAB was first determined as part of the 2007 determination. We understand that UR has constructed a notional RAB for 2004 to estimate the implicit MAR. We considered that both MAR estimates were of questionable reliability. In respect of the 2004 estimate, PNGL did not have a defined RAB at this time, and PNGL was acquired by Terra Firma as part of a portfolio of assets making the valuation of PNGL as a part of that acquisition uncertain. Terra Firma's current valuation of PNGL is not based on a market transaction and is subjective. We did not investigate the transaction values in depth because we did not consider that they were likely to provide relevant evidence in context of this determination. We considered that a variety of factors, such as general market demand for infrastructure investments, the political climate in Northern Ireland, the prevailing regulatory arrangements (including the lack of a defined RAB), regulatory uncertainty due to lack of clarity in 2004 as to the future of the regulatory regime, and investor's expectations of PNGL's ability to recover its investments, might have been expected to result in a MAR below 1 in 2004. That the MAR increased in the run-up to the 2007 determination is not surprising, as uncertainty in a number of these areas was resolved.

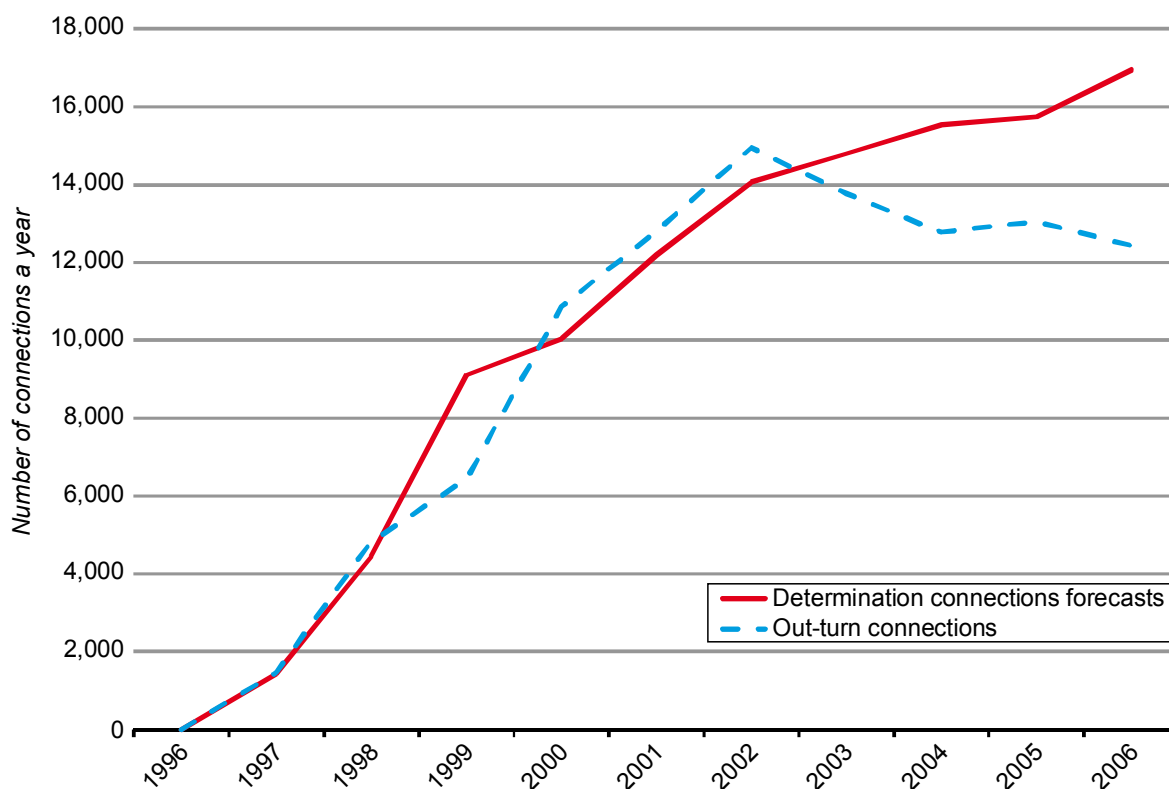
The maturity of PNGL

- 7.62 Noting that PNGL was a start-up business in 1996, we looked at its stage of development in 2007 compared with other established Great Britain utilities. In doing so, we considered the profile of gas connections, the profile of capex, and of cash flows.
- 7.63 To some extent, PNGL had established a customer base by 2006. In fact, PNGL noted that by 2006 it had 'attracted sufficient customer connections to ensure that positive cash flows could sustainably be generated in subsequent periods'. However,

PNGL underperformed against its connections targets in 2003–2006. This is shown in Figure 7.3 below, and demonstrates the uncertainty around the uptake of gas connections and resultant vulnerability of the network’s demand. The fact that PNGL was still growing its customer base in 2006 suggests the relative immaturity of the network and higher volume risk compared with Great Britain utilities. Further, we note that its customers’ patterns of demand would be less well understood compared with other Great Britain utilities.

FIGURE 7.3

Annual connections forecasts and out-turns, 1996–2006

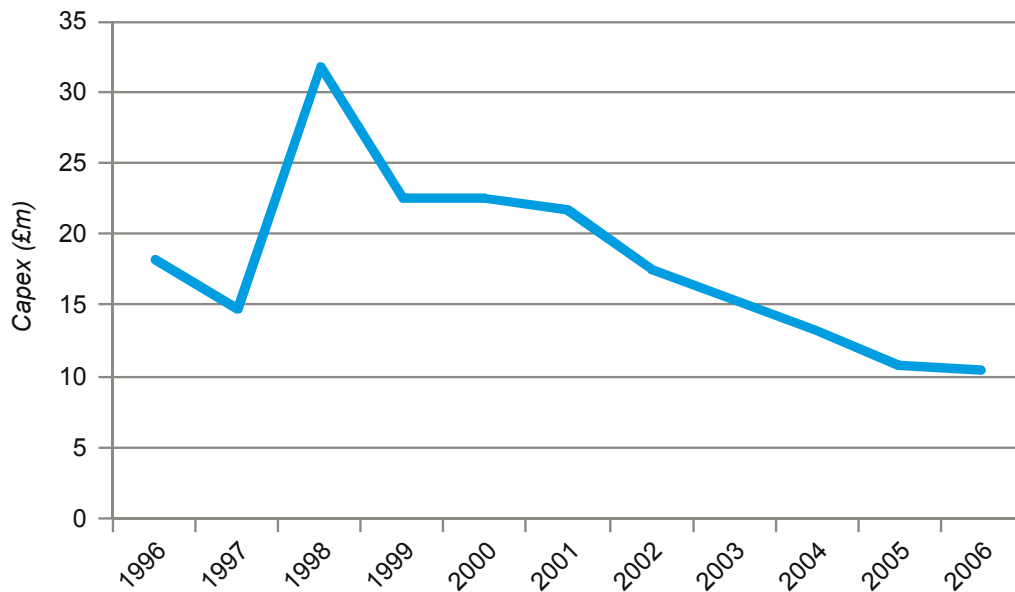


Source: PNGL.

7.64 In relation to capex, the evidence suggests that by 2006 PNGL’s successful capex programme in the preceding decade had considerably reduced forward-looking capex projections and that by this stage PNGL’s business model approximated an established network with ongoing maintenance costs rather than considerable amounts of new construction. We understand that PNGL planned further connections and network build-out; nonetheless, it can be seen that capex had declined considerably by 2006, as shown in Figure 7.4.

FIGURE 7.4

PNGL capex costs, 1996 to 2006

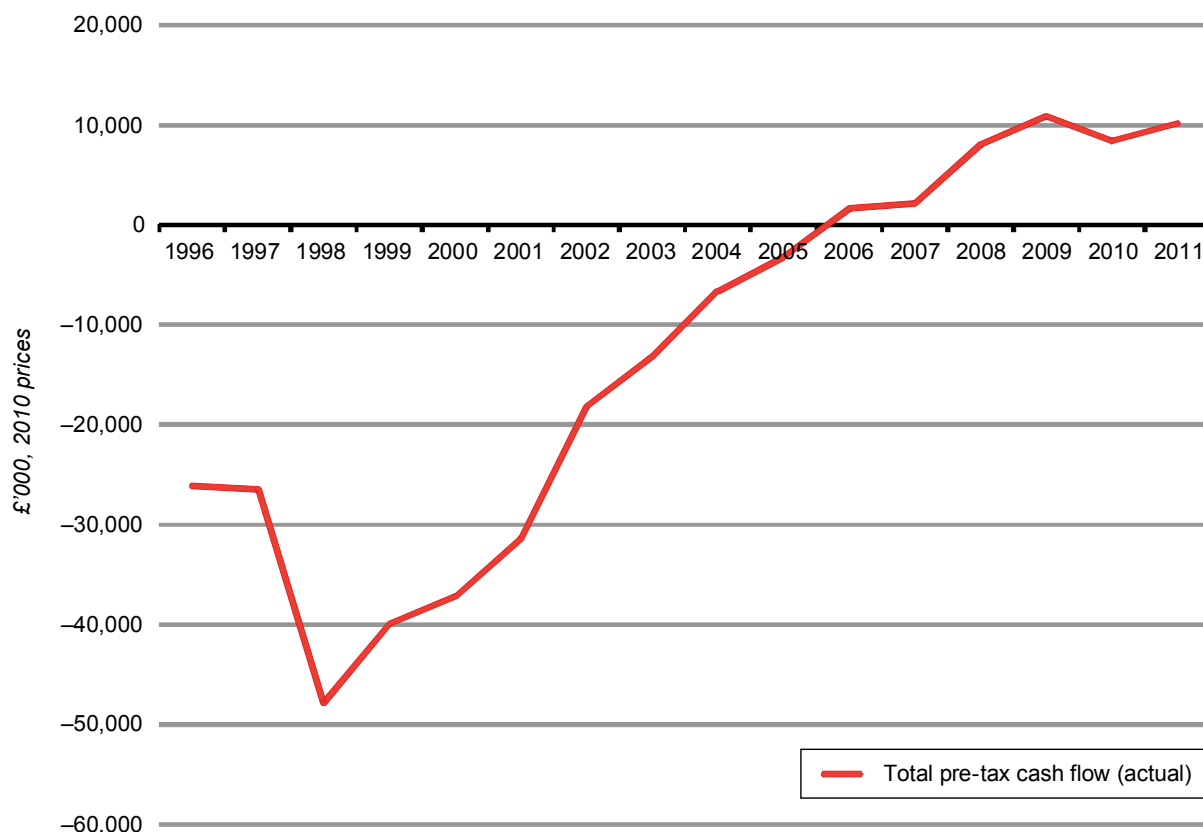


Source: PNGL data.
Note: In 1996 prices.

- 7.65 Supporting evidence on the relative maturity of PNGL's network infrastructure by 2006 is affirmed by PNGL's surpassing of network outreach targets by PC03: '[PNGL] had made a significant investment in the gas network infrastructure required to provide natural gas to Northern Ireland; it was ahead of target for meeting its mandatory licence requirement to pass 81% of properties by 2008'.
- 7.66 We also considered PNGL's cash-flow profile. Figure 7.5 below demonstrates that as of 2006, PNGL was only just beginning to generate positive cash flows and the cash flows were only marginally positive. We note that it is not necessary that a mature utility would be consistently cash-flow positive. PNGL's lack of a track record of stable and predictable cash-flow generation, in contrast to many mature Great Britain utilities, may have reduced its relative attractiveness to potential investors.

FIGURE 7.5

PNGL's total pre-tax cash flows since 1996



Source: PNGL [statement of case](#), Figure 4, p74.

PNGL's WACC in 2007

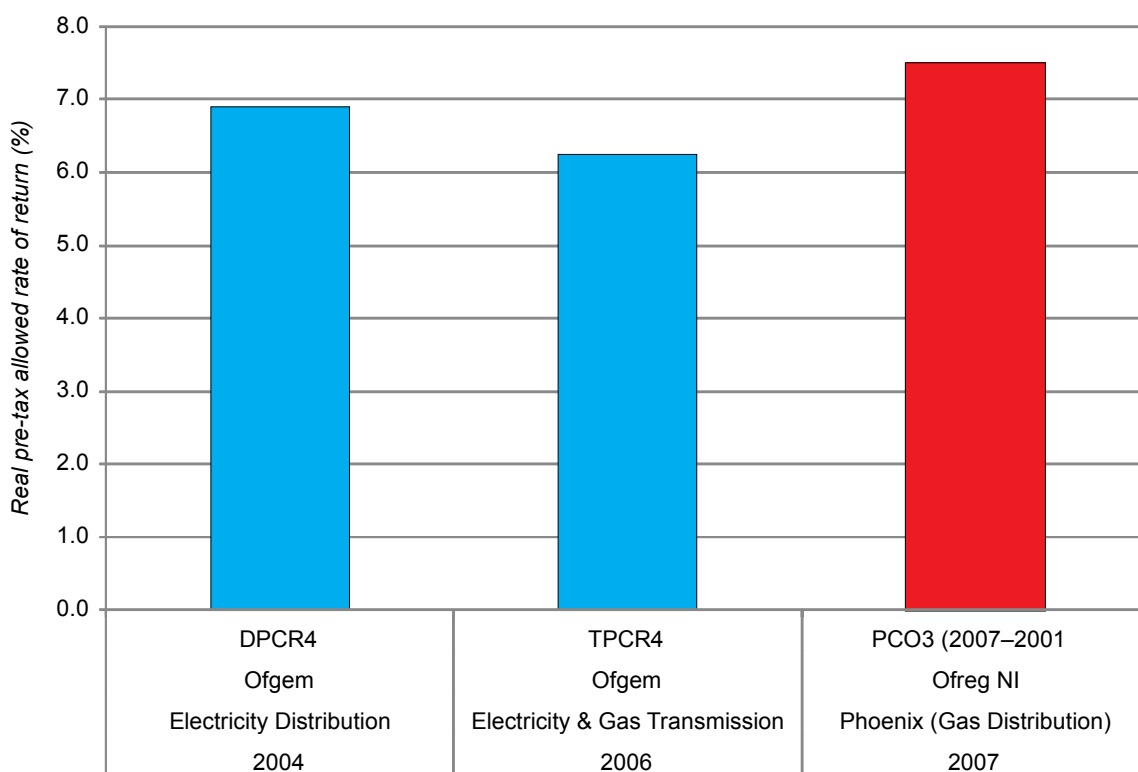
- 7.67 Taking into account the effect of the various factors discussed above on PNGL's risk profile, we now consider the forward-looking WACC faced by PNGL in 2007. Given that PNGL is not listed, it is not possible to observe its cost of equity capital from stock market data, hence much of the following discussion focuses on how its WACC might compare with that of Great Britain utilities. However, PNGL issued a listed bond in 2009 and we have considered the cost of this debt in our assessment (see [paragraph 7.73](#)).
- 7.68 We note that the parties disagree on how the rate of return allowed in 2006 for PNGL compares with the rate of return allowed for mature Great Britain utilities:
- (a) UR argued that in 2007 Ofgem allowed Great Britain Gas Distribution Networks (GDNs) to earn a real pre-tax return of 6 per cent. It suggested that the 1 per cent reduction in PNGL's allowed return between 1996 and 2007 exactly matched the 1 per cent reduction in the Great Britain GDNs' allowed return over roughly the same period. Therefore, UR contended that the (1.5 per cent) premium that PNGL had been earning relative to Great Britain GDNs since 2007 had been the same as the premium earned in the preceding ten years, despite the apparent de-risking of the business in 2006.
 - (b) PNGL submitted evidence on a number of price control decisions between 1991 and 2006 for Great Britain utilities (set out in Appendix G). On the basis of these

decisions, it argued that the allowed rate of return for mature utilities declined by 0.1 to 0.75 per cent between 1996 and 2006, and not by 1 per cent as UR stated.³³ It therefore contended that the 1 per cent decline in the allowed return for PNGL went beyond the general reduction seen by other regulated utilities due to changes in general financial market conditions.³⁴ It also argued that there were potential comparators for PNGL besides mature Great Britain utilities that should be considered, for example the real rates of return for firmus (2005, 7.5 per cent),³⁵ Independent Gas Transporters (2006, 8.5 per cent)³⁶ and BT (1992, 11 to 12 per cent).³⁷

7.69 We note that it does appear from a review of the price controls in Great Britain energy network regulation from the mid-2000s that PNGL received an allowed rate of return as part of the 2007 determination which was about 0.6 to 1.3 per cent higher than the WACC allowed to mature energy utilities in contemporaneous 2004 to 2006 price control decisions, as shown in Figure 7.6.

FIGURE 7.6

Allowed rate of return for PNGL in PC03 relative to other Great Britain energy utilities



Source: CC and Oxera analysis based on various regulatory documents.

7.70 We also considered PNGL's submissions (in paragraph 7.15 **Error! Reference source not found.** and Appendix G) on the use of comparators besides the relatively mature Great Britain regulated utilities. We looked at BT, firmus and IGTs.

³³ PNGL response, paragraph 2.19, p89.

³⁴ PNGL response, paragraph 2.19, p89.

³⁵ PNGL response, paragraph 2.21, p89.

³⁶ PNGL response, paragraph 2.24, p89.

³⁷ PNGL response, paragraph 2.26, p90.

- (a) We considered that the rate of return allowed to BT in 1992 is not a good comparator for PNGL's rate of return in 2006 due to differences in timing and in underlying risk factors.
- (b) We consider that firmus—another Northern Ireland GDN which began operations in 2005—could be a reasonable comparator for PNGL. However, there are timing issues in comparing the two firms because firmus was a greenfield investment in 2005 while PNGL had been operating for nine years by that time.
- (c) We considered the possibility that the reasonable profits test applied to legacy assets for Independent Gas Transporters (IGTs) in Great Britain provided a potential comparator for the rate of return allowed to PNGL in 2006. However, we note that IGTs were not subject to detailed economic regulation in the same manner as Great Britain GDNs or PNGL.³⁸

7.71 We note that the changes to the regulatory framework brought about by PC03 moved PNGL on to a footing that was similar to that of Great Britain utilities but which represented a substantially new framework for PNGL and there remained areas of uncertainty that required clarification in the future.

7.72 In summary, we were not able to find a good comparator for PNGL's forward-looking WACC in 2007. We thought that the nearest comparator companies were Great Britain utilities. However, we noted that these entities faced more predictable demand and a more established and developed regulatory framework than did PNGL at this time. We identified that PNGL's allowed rate of return in 2007 was around 0.6 to 1.3 percentage points higher than mature Great Britain energy utilities in contemporaneous 2004 to 2006 price controls (see Figure 7.6). We consider that part of this differential may be justified by PNGL's relative immaturity, and hence relatively higher forward-looking WACC.

7.73 We took into account evidence on PNGL's cost of debt. This is set out in detail in Section 8. We find that there is evidence of a differential in bond yields between Great Britain utility bonds of a similar credit rating and that of PNGL, that has averaged 70 basis points over the period since the bond was issued in November 2009. We note the difficulties of making this comparison, and whilst we cannot conclude on the specific factors giving rise to the differential, we consider that this evidence is consistent with our view that PNGL's WACC was above that of Great Britain comparators in 2007.

7.74 Given the lack of data, we found it hard to estimate the forward-looking WACC faced by PNGL in 2007 with precision. However, it is our view that it was likely to have been less than 7.5 per cent.

7.75 Hence we concur with the views of UR and PNGL that the 7.5 per cent rate of return exceeded the forward-looking WACC in 2007 because it contained a project-specific risk premium. We now consider the justification for this.

Whether the project-specific premium should be retained

7.76 We considered that PC03 represented an important reform of the original regime which was beneficial to consumers and to PNGL and which resolved many of the problems associated with the original regime. Most notably, it increased the period over which PNGL could recover its investments, so improving PNGL's incentives to

³⁸ Ofgem, *Independent Gas Transporter Charges and Cost of Capital*, February 2002, p1.

continue to invest in the network,³⁹ and thus reducing the risk of large price increases for consumers.⁴⁰ However, we note above that PC03 did not remove all uncertainty; there were a number of unresolved areas, such as the connections revenue driver, which was not resolved until later, and the extension of the recovery period meant that revenues were profiled many years into the future.⁴¹

- 7.77 We considered UR's argument that all of the asset stranding uncertainty was to have played out in 2006 to 2016 under the original licence and was eliminated by the 2007 determination (see Appendix D).
- 7.78 We think that there was real uncertainty over PNGL's ability to recover its investments leading up to the 2007 determination and that the PC03 framework removed much of this uncertainty by introducing a RAB and extending the licence recovery period.
- 7.79 We viewed the 2007 determination as a change to the original 20-year project rather than terminating (and fully rewarding) the initial project and starting a new investment project in its own right. While the determination and publicity at the time noted the beneficial effect of these changes (particularly in extending the licence period), they did not portray this as a fundamental new start to the regime, nor was there consultation on the proposed changes on this basis, and the 2007 determination carried forward capitalized historic outperformance and continued to recognize the principle of a 20-year agreed rate of return. We considered that there could be justification for retaining elements of the original licence conditions, including the commitment to reward PNGL with a fixed rate of return for a period of 20 years. In our view, the project-specific risks that PNGL assumed in 1996, and the distinct possibility that PNGL was under-rewarded for risks between 1996 and 2007, remain relevant considerations. At the least, after 2006 PNGL ceased to receive the reward for assuming project risk that it had expected to receive for a 20-year period.
- 7.80 We also note that there is some evidence of a shared market perception that the current rate of return allows a compensation for the initial risks of PNGL's investment. For example, Fitch Ratings has noted:
- The licence provides for a cost of capital in terms of pre-tax WACC of 7.5% until the end of 2016. This rate includes a premium for the developer of the gas distribution network in NI as compensation for project/construction risk and, therefore, ranges higher than comparables of Ofgem regulated entities.
- 7.81 While we consider that PC03 represented a change to the original project which did remove some uncertainty, and which is reflected in the reduction of the rate of return at that time, in the context of all the changes that occurred at the time (and because we consider this to be a continuation of the existing project) we think that there was adequate justification for not departing from retaining a fixed rate of return for the remainder of the original 20-year period that incorporated a return for project-specific risk.
- 7.82 Moreover, whilst in 2007 PNGL was better established, it was a still-developing network utility which remained immature compared with Great Britain utilities. As a

³⁹ The extension of the period reduced the risk that PNGL would not recover its investment within the licence period and so improved PNGL's incentives to continue to invest in the network.

⁴⁰ The prospect of price increases in the run-up to the 2007 determination is discussed in Section 2.

⁴¹ Hence recovery of costs would be dependent on levels of demand far into the future which are inevitably hard to forecast and inherently subject to risk (although mitigated by the process of periodic price redeterminations).

result, we conclude that the forward-looking WACC was likely to be relatively high in comparison with Great Britain utilities. We believe that the considerations noted above support the PC03 decision to fix a 7.5 per cent rate of return until 2016.

Rate of return in 2012/13

- 7.83 Having considered the justification for the rate of return being set at 7.5 per cent in 2007, we now consider whether it remains appropriate to continue with this fixed rate of return of 7.5 per cent in 2012/13.
- 7.84 We first considered the evidence presented by UR and PNGL regarding the forward-looking WACC in 2012/13.
- 7.85 UR has estimated a forward-looking real pre-tax WACC of 5.1 to 5.5 per cent for PNGL for the period 2012/13. This does not include compensation for project-specific risks. The components of this WACC estimate are shown in Table 7.1.

TABLE 7.1 UR projected real cost of capital for 2012/13

	<i>UR (low)</i>	<i>UR (high)</i>
Gearing (%)	67.5	67.5
Cost of debt (%)	3.35	3.35
<i>Cost of equity</i>		
Risk free rate (%)	2.0	2.0
Equity risk premium* (%)	4.5	5.0
Equity beta	1.02	1.10
Post tax cost of equity (%)	6.6	7.5
Tax rate (%)	23.875	23.875
Pre-tax cost of equity (%)	8.7	9.9
Pre-tax WACC (%)	5.1	5.5

Source: UR.

*UR does not report the equity risk premium directly—it reports the market return which comprises the risk-free rate and the equity risk premium. Also UR makes an implicit debt beta assumption of 0.1.

- 7.86 PNGL has estimated a forward-looking real pre-tax WACC of 6.6 to 7.7 per cent for PNGL for the period 2012/13. The components of this WACC estimate are shown in Table 7.2.

TABLE 7.2 **PNGL projected real cost of capital for 2012/13**

	<i>PNGL (Low)</i>	<i>PNGL (High)</i>
Gearing (%)	55	55
Cost of debt (%)	4.3	4.4
<i>Cost of equity</i>		
Risk free rate (%)	2.0	2.0
Equity risk premium (%)	5.25	5.25
Equity beta*	N/A	N/A
Post tax cost of equity (%)	7.1	8.9
Tax rate (%)	24	24
Pre tax cost of equity (%)	9.4	11.7
Pre tax WACC (%)	6.6	7.7

Source: PNGL.

*PNGL does not report its own equity or asset beta assumption. It estimates the asset beta for a mature utility as 0.4–0.46, assumes gearing of 60 per cent, makes a debt beta assumption of 0.1 and thereby infers a pre-tax cost of equity for a mature utility of 8.5 to 9.5 per cent. It then adds on a premium for its equity investors of 1.1 to 2.2 per cent to reflect its small size, relative immaturity and Northern-Ireland-specific factors. It is not clear how this premium is incorporated; if added to the pre-tax cost of equity, this uplift suggests a pre-tax cost of equity of 9.6 to 11.7 per cent (ie 8.5 + 1.1 = 9.6% and 9.5 + 2.2 = 11.7%). However, PNGL reports 9.4 to 11.7 per cent as shown in this table.

- 7.87 Based on the above evidence, we consider that the forward-looking WACC in 2012/13 for PNGL, excluding any ongoing compensation for project-specific risks, is likely to be lower than the allowed rate of return of 7.5 per cent. However, we have not undertaken a detailed assessment of the current WACC for PNGL.
- 7.88 We considered whether there was adequate justification for changing the rate of return of 7.5 per cent that was agreed and fixed in 2007 for a ten-year period. As set out above, we considered that in 2007 there appeared to be justification for setting a rate of return that was above the forward-looking WACC to compensate PNGL for the project-specific risk that it had faced when making its original investment. We observe that the forward-looking WACC for PNGL in 2012 and 2013 is likely to be lower than 7.5 per cent, because PNGL is increasingly mature, and that the regulatory framework has become more standardized. On the other hand, revenue continues to be deferred into the future and elements of the regulatory regime are still developing, and there is a need to ensure continued investment in the network in the future. We have seen nothing to indicate that circumstances have changed such that the commitment made in 2007 to fix the rate of return until 2016 should be revisited. However, we recognize that there is a judgement to be made about the length of time over which it continues to be appropriate to maintain a fixed rate of return above the forward-looking WACC, in a context where such important revisions have been made to the original approach but where continued expansion still needs to be ensured. This judgement must be made against the question of whether maintenance of the fixed rate operates, or may be expected to operate, against the public interest, balancing the interests of PNGL and of consumers, and taking into account the effects of regulatory uncertainty.
- 7.89 Our views on regulatory uncertainty are set out in Section 8.
- 7.90 Our evaluation of whether the continuation of a rate of return of 7.5 per cent for the period 2012/13 is in the public interest is set out in Section 9.

8. Implications for regulatory certainty and cost of capital

Introduction

- 8.1 As noted in paragraphs 2.61 to 2.82, at PNGL12 UR proposed a reduction of the TRV of around £75 million for historic outperformance and deferred capex. PNGL argued that the 2012 TRV adjustment substantially and retrospectively reduced the 2006 TRV value that was embedded within PNGL's licence, and this caused considerable regulatory uncertainty, severely undermined investor confidence and changed the basis on which PNGL had taken its investment decisions since 2006. It said that this was to the detriment of both PNGL and its customers, and to the task set for PNGL of introducing a natural gas infrastructure to Northern Ireland.¹ In this section, we consider the possible consequences that could arise in the event of changes to the regulatory framework with specific reference to UR's proposals to remove elements of historic outperformance and deferred capex from the TRV. We also consider the possible consequences of revisiting the rate of return that was written into the licence and stated as fixed for ten years in 2007.
- 8.2 We note that the reference requires us to consider whether the existing arrangements are against, or are expected to operate against, the public interest; remedial changes to the existing framework are relevant only in circumstances where existing arrangements are found to be against the public interest. However, it is possible that changes to arrangements may themselves create undesirable consequences. If remedies are to be contemplated on public interest grounds, it would be important to consider any possible adverse consequences in deciding on whether such remedies should be pursued.
- 8.3 We now consider the evidence from UR and PNGL in respect of these issues. We also consider the evidence, from a variety of submissions including the ratings agencies, infrastructure investors and consumer bodies, on whether UR's decisions would be likely to impact on PNGL's credit ratings and its cost of capital.

PNGL's views on the implications of UR's proposals to reduce the TRV

- 8.4 PNGL said that UR's proposed actions to reduce the TRV carried significant costs (in particular, when considering that PNGL's business had only recently begun to generate positive cash flows).² This was because:
- UR's proposals undermined investor confidence that the regulated company could recover a pre-agreed asset value,³ and undermined investors' confidence that any other decision of UR will escape similar treatment in the future.⁴ PNGL argued that the 2006 'agreement' on the package of modifications and the 2007 licence modifications had been a major regulatory decision reached after extensive consultation, and so if UR was willing to cherry-pick retrospectively the results of such an extensive exercise, investors could have no confidence over any other decision.⁵

¹ PNGL [statement of case](#), paragraph 1.8.

² PNGL [statement of case](#), paragraphs 1.50, 1.53.

³ PNGL [statement of case](#), paragraph 1.51.

⁴ PNGL [statement of case](#), paragraph 1.55.

⁵ PNGL [statement of case](#), paragraph 1.55.

- This confidence was a cornerstone of incentive-based regulation,⁶ as it underpinned incentives to operate efficiently and raise finance at efficient cost.⁷
- UR's proposals undermined investment incentives going forward.⁸ It potentially established a reputation that risked raising the cost of capital and discouraging investment across the energy and utility sectors in Northern Ireland.
- Promoting efficient investment was an important part of promoting the long-term interests of consumers and it was consumers who would ultimately bear the costs of regulatory failures that prevented efficient delivery of investment.⁹ PNGL said that a stable TRV allowed regulated companies to secure financing on reasonable terms and at an efficient cost.¹⁰
- A predictable methodology for the treatment of the asset value, which excluded retrospective adjustments, was central to investors' confidence in the recovery of investment in long-lived assets. It was fundamental to the perceived low regulatory risk in the Great Britain regulatory system and the financing terms that were associated with such a low level of risk.¹¹

8.5 PNGL said that this was demonstrated by the emphasis rating agencies placed on the regulatory environment. It said that Moody's, for example, placed 40 per cent of its overall assessment in its credit rating decision on this element (15 per cent out of the 40 per cent were for Moody's view of the stability and predictability of the regulatory regime). PNGL said that if its score under this element of Moody's assessment was lower, then this would lead to a worse credit rating and higher financing costs, at a given level of gearing.¹²

8.6 PNGL said that it was clear that the 2012 TRV adjustment would result in a lower score for PNGL under Moody's category of 'Regulatory Environment and Asset Ownership'.¹³ PNGL said that since 2009 (when it was first awarded its rating) it had consistently been awarded an Aa grade by Moody's in this category.¹⁴ The 2012 TRV adjustment had the potential to bring about a significant mark-down of three notches from Aa to Ba which represented 'regulatory framework that is defined but not consistently applied'.¹⁵ PNGL said that the 2012 TRV adjustment also meant that PNGL's regulatory environment was now unlikely to reach the Aaa score (which was the score for the Great Britain regulatory regime).¹⁶

8.7 PNGL said that the proposed 2012 TRV adjustment had already had a tangible impact on investor confidence. In October 2011, Fitch Ratings (Fitch) placed PNGL on negative watch, anticipating a downgrade should UR's proposals be adopted. It said that in May 2012, Fitch confirmed a negative outlook for PNGL pending the outcome of this inquiry, and confirmed that a 'revision of financial guidelines may lead to a ratings downgrade'¹⁷ (see paragraph 8.39). A month earlier, Moody's stated that 'In the event that the Competition Commission rules against PNG, Moody's cannot exclude the possibility that its credit rating could be affected' (see paragraph 8.49).

⁶ PNGL [statement of case](#), paragraph 1.51.

⁷ PNGL [statement of case](#), paragraph 1.51.

⁸ PNGL [statement of case](#), paragraph 1.51.

⁹ PNGL [statement of case](#), paragraph 6.23.

¹⁰ PNGL [statement of case](#), paragraph 6.24c.

¹¹ PNGL [statement of case](#), paragraph 6.17.

¹² PNGL [statement of case](#), paragraphs 6.18, 6.29–6.32, Figure 5.

¹³ PNGL [statement of case](#), paragraph 6.33.

¹⁴ PNGL [statement of case](#), paragraph 6.34.

¹⁵ PNGL [statement of case](#), paragraph 6.35.

¹⁶ PNGL [statement of case](#), paragraph 6.36.

¹⁷ Fitch Ratings statement, 2 May 2012.

- 8.8 PNGL said that a lower score would impact on its cost of finance.¹⁸ It said that since gearing was the main driver of the key credit metrics, it was either this factor that would need to be improved to counterbalance the downgrade in the ‘Regulatory Environment and Asset Ownership’ category or PNGL would have to pay higher borrowing costs.¹⁹ It said that a lower level of gearing would leave the cost of debt the same as previously, given that the credit rating had been maintained, but this would result in a higher cost of capital due to the higher proportion of equity and any additional increases in the cost of equity that resulted from the increase in regulatory risk.²⁰
- 8.9 PNGL said that it could draw no comfort from UR’s assurance that there would be no impact on the cost of capital or regulatory certainty following the PNGL12 price control determination, because the proposals related to historic issues that could be considered to be finalized and closed. It said that UR’s statement that the 2012 TRV adjustment was a one-off and would have no impact on regulatory risk was incorrect.²¹ This was because:²²
- (a) UR said that it could give no assurance that PNGL’s asset base would not be revisited during future price control reviews because this would be inconsistent with and overridden by UR’s statutory duties. Furthermore UR had already stated a similar intention at the time of the 2006 Agreement on the package of modifications, where UR said that the 2006 Agreement would provide a *stable basis* on which to make future investments and grow the market.²³
 - (b) Any unpredictable decision would raise concerns relating to the future behaviour of the regulator, both in relation to the company and other sectors it regulated.²⁴ In support, PNGL referred to the Pipes and Wires Report of the National Audit Office,²⁵ which noted that one important aspect of investor perceptions was their view of the future direction of the regulatory regime, and if this was not clear then ‘investors may therefore perceive the regulatory regime as uncertain and hence raise the required return from their investments’ and that the costs of regulatory uncertainty were sufficiently high to lead to a recommendation of improvements in regulatory practice to promote greater transparency and predictability.²⁶
 - (c) The TRV was a central element to economic regulation in the UK, there was a consistent regulatory precedent and best practice for the treatment of the TRV (and a departure from this general precedent would be viewed as a departure from the established methodology, rather than the specifics of the decision) and the TRV was very important to investors (illustrated by the reactions of the rating agencies to the 2012 TRV adjustment).²⁷
- 8.10 PNGL said that if UR was allowed to ‘cherry-pick’ and retrospectively revisit aspects of the 2006 ‘agreement’ on the package of modifications that was subject to extensive negotiation and public consultation, then PNGL and its investors could have no confidence that any agreed or apparently fixed aspect of the regulatory regime would not be subject to revision at a later point in time.

¹⁸ PNGL [statement of case](#), paragraph 6.37.

¹⁹ PNGL [statement of case](#), paragraph 6.37.

²⁰ PNGL [statement of case](#), paragraph 6.40.

²¹ PNGL [statement of case](#), paragraph 6.21.

²² PNGL [statement of case](#), paragraph 6.22.

²³ PNGL [statement of case](#), pp1, 2, Annex 9.

²⁴ PNGL [statement of case](#), paragraph 6.22a.

²⁵ [NAO Pipes and Wires Report](#).

²⁶ See PNGL [supplementary submission](#), Annex 2.

²⁷ PNGL [statement of case](#), paragraphs 6.22b, 6.22c.

- 8.11 PNLG considered that the balance of probability was that the rating agencies would downgrade its rating by at least one notch if UR's proposed retrospective adjustment to TRV was upheld. It believed that any rating downgrade would be largely in response to uncertainty over regulatory regime rather than purely credit metrics. If a downgrade resulted in PNLG's debt becoming sub-investment grade, it claimed that this would have severe consequences: it said that PNLG would be in a position where it was no longer able to meet its obligations under Condition 1.22 of its licence (which required PNLG to maintain an investment-grade credit rating), which could lead to enforcement action being taken by UR. In addition, it said that the majority of current debt holders would be forced to sell, quite possibly at a loss. Consequently, it believed that any downgrade would result in an increased cost of debt and if it became sub-investment grade this increase would be substantial. In addition, the impact of the change to TRV would be to delay further any dividend payments to equity, further increasing PNLG's cost of equity.
- 8.12 In response to UR's statement that the cost of capital it faced would still be below its allowed rate of return (see paragraph 8.27), PNLG said that the 7.5 per cent WACC was set in the 2007 determination to reflect a range of factors, including the long-term nature of the original 20-year investment. It said that it was not justified for UR to make changes just so long as the WACC was sufficient to withstand such interventions.

Wider costs to other industries

- 8.13 PNLG said that the precedent of UR's decisions (if upheld by us) could increase uncertainty or delay or deter investment both within regulated industries in Northern Ireland and also elsewhere. The precedent value of this approach would be that it then raised a risk that any regulator in the UK could see a chance to make retrospective changes to claw back value from regulated companies.²⁸
- 8.14 PNLG said that UR's proposal raised a particular concern for investors in greenfield infrastructure assets (including those looking to take gas to new areas of Northern Ireland). This was because the expected profile of cash flows for such investments required that investors must be confident that the regulator would allow a period of profits in order to compensate for an upfront period of losses.²⁹ Opportunistic asset write-downs risked making greenfield investments into long-lived assets costlier than they would otherwise be, or might not even be made at all.³⁰
- 8.15 PNLG said that costs would also arise as the companies UR regulated would therefore have diminished incentives to deliver cost efficiencies, since they would anticipate a risk that any agreed share of benefits that the company should retain would be taken away ex post. The impact on productivity would be significant, and costs would be higher than they otherwise would have been.³¹
- 8.16 PNLG said that this impact on the cost of capital would also be likely to be felt by other utilities in Northern Ireland, as credit rating agencies would apply their regulatory risk assessment across the whole sector.³² PNLG further said that unless we

²⁸ PNLG noted that National Grid, as part of its current price control review with Ofgem, had referenced UR's PNLG12 Final Decisions document as evidence of 'the very real nature and presence of regulatory risk'. See PNLG [statement of case](#), paragraph 6.20.

²⁹ PNLG [statement of case](#), paragraph 1.53.

³⁰ PNLG [statement of case](#), paragraph 1.53.

³¹ PNLG [supplementary submission](#), paragraph 2.11b.

³² PNLG [statement of case](#), paragraph 6.41.

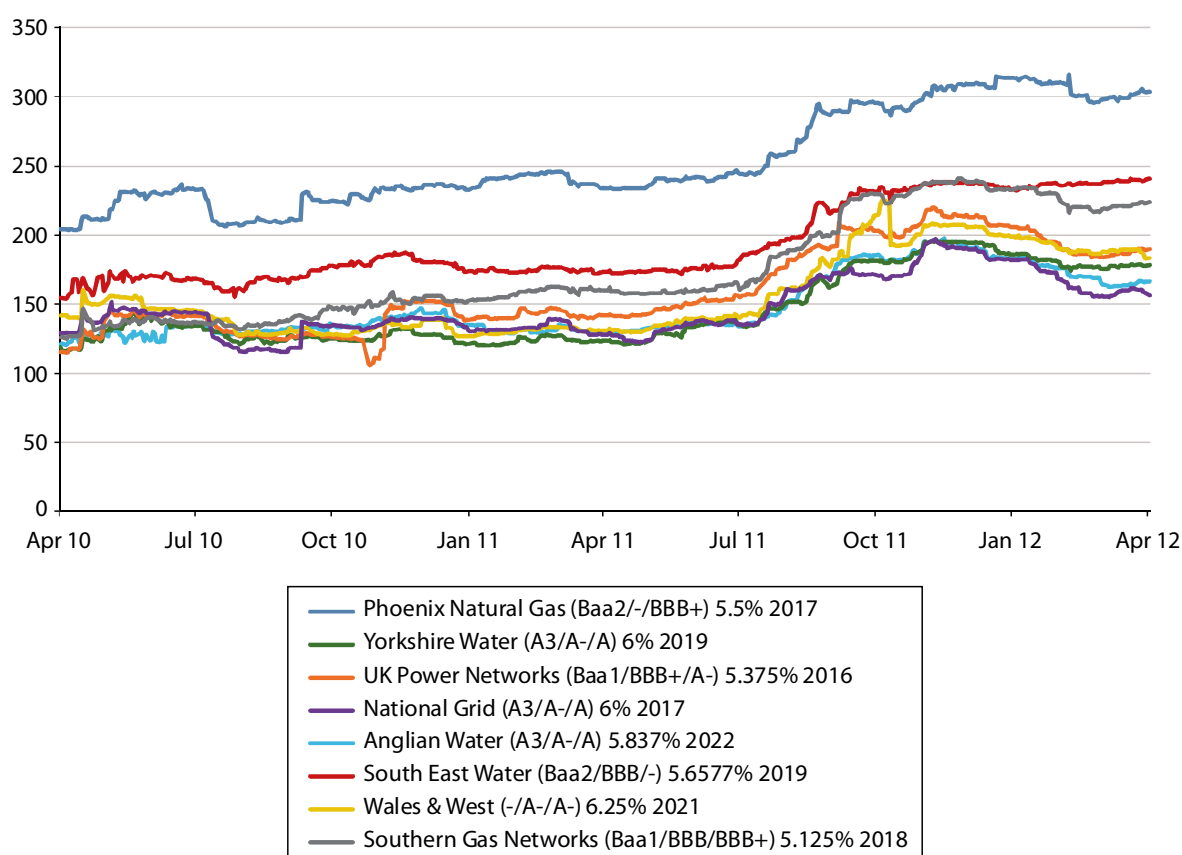
established a transparent and predictable framework, these risks might spread across all regulated utility sectors in Great Britain.³³

PNGL's evidence on debt premiums

- 8.17 PNGL argued that there was 'a significant and persistent premium that is paid for PNGL's debt over typical GB utilities debt'. PNGL indicated that it thought this was evidence that the regulatory regime in Northern Ireland was seen as less certain than in Great Britain.
- 8.18 PNGL submitted evidence from RBS on spreads for PNGL's bond compared with Great Britain market peers over the last two years. This is shown in Figure 8.1.

FIGURE 8.1

Spreads on PNGL's debt compared with Great Britain market peers



Source: PNGL.

- 8.19 PNGL argued that its cost of debt should be estimated as 110 bps higher than debt issuance by mature Great Britain utilities. However, PNGL's citation of RBS's commentary on Figure 8.1 suggests that the closest comparable bond in terms of rating is the South East Water bond relative to which PNGL's differential in spreads is 'on average 60 bps'.
- 8.20 PNGL also argued that the 'bond yield data clearly indicates an increase in the spread over GB comparators at around the time of the Authority's initial PNGL12

³³ PNGL [statement of case](#), paragraphs 1.52, 5.2, 6.15, 6.23, 6.24b, 6.41.

proposals in August 2011'. We assess PNGL's evidence on debt premiums in paragraphs 8.100 to 8.109.

UR's response

- 8.21 UR said that PNGL's submissions that the modifications would have a large and prolonged adverse impact on investor confidence were not substantiated.³⁴ UR said that it accepted that regulatory certainty was important, but that PNGL had not substantiated (or quantified) its claim that the proposed 2012 TRV adjustment would have a large and prolonged adverse impact on investor confidence.³⁵ It said that if there were any impact on investor confidence, there was no basis to conclude that its effect would approach the value of the proposed TRV adjustment.³⁶ UR calculated that to match the £80 million of TRV adjustment, the adverse effect on the cost of capital would have to be 1.8 per cent from 2017 until 2046, which it said was not plausible. UR modelled that the cost to the gas industry would be between £0.1 million and £36.5 million if the 'regulatory risk premium' increased the cost of capital for PNGL, firmus and Gas to the West for five to ten years by 0.25 to two percentage points.³⁷
- 8.22 It further submitted that there was an uncertain benefit from enabling expansion of the natural gas industry in Northern Ireland because 'significant gas extensions that remain in NI are not commercially viable and require some form of subsidy/subvention e.g. for a transmission pipeline.'³⁸
- 8.23 UR said that it had provided a supportive regulatory framework to PNGL, and its actions were necessary to ensure a balanced outcome in the public interest. While UR said it recognized that certainty was a desirable aim of best regulatory practice, not least in the context of a regulated asset base, it said that this did not mean that the concept of certainty should be elevated to a status equivalent to that of the statutory duties, as if it were an end in itself. It said that its role in regulatory theory and practice was instrumental, to the extent that it served the public interest. UR did not accept that the adjustment would act as a deterrent to the development of the gas industry in Northern Ireland, because:
- the specific proposals to which PNGL objected related not to past investment but to the treatment of monies that the company did not spend;
 - the proposals were careful to ensure that customers paid for all efficiently incurred capitalized expenditure that PNGL had actually put into gas network in Northern Ireland since 1996 including the licence allowed cost of capital;
 - the proposals set out a commitment to ensure that customers would pay for all future capitalized expenditure that PNGL efficiently incurred; and
 - in so far as PNGL had to finance investment ahead of payment by customers, it was to be allowed a real pre-tax return of 7.5 per cent a year until 2017—the highest cost of capital allowance that was on offer to a comparable regulated business in the UK.³⁹

³⁴ UR [supplementary submission](#), paragraph 1.10.

³⁵ UR [supplementary submission](#), paragraphs 1.10, 2.18.

³⁶ UR [supplementary submission](#), paragraph 1.13.

³⁷ UR [response to provisional determination](#), Table 1.

³⁸ UR [response to provisional determination](#), paragraph 1.10.

³⁹ UR [statement of case](#), paragraph 3.30b.

- 8.24 UR said that the PNGL case was a complex one with a unique history and that the adjustment to TRV would mean that all the historical outperformance issues had been dealt with and would move PNGL towards a more standard approach. UR said that the specific circumstances UR was dealing with here would not arise again.⁴⁰ It said that, in its view, investors in regulated industries were sophisticated enough to separate and distinguish a one-off ‘starting point’ issue—especially one that related to the rewards a company should earn for money that it did not spend—from the risks that impacted on their investment once a new regulatory regime had bedded down⁴¹ and related to regulatory risks impacting on stable regulatory regimes.⁴²
- 8.25 UR said that PNGL also highlighted the importance of a ‘supportive regulatory framework’ to the investment community. UR said that the evidence in relation to PNGL since 1996 clearly demonstrated that such a framework existed in Northern Ireland. UR said that it had taken a number of actions over the years to ensure that the industry continued to grow. The most relevant was the decision to restructure the PNGL licence when the original business plan failed to prove viable. This allowed an investment grade credit rating for PNGL. It was not clear what the credit rating would have been without the 2007 licence modifications. Other examples of a supportive regulatory framework included allowing PNGL advertising and marketing allowances, and sales team manpower allowances (so PNGL could expand its markets and treat these costs as part of its overall investment), and allowing PNGL not to charge the cost of connections to customers.⁴³
- 8.26 UR said that since it acknowledged the importance of the cost of capital, it had carefully considered the impact its decisions may have on the ability of PNGL to attract affordable finance. UR had carried out a thorough and robust assessment of PNGL’s financeability to satisfy itself that the company could continue to raise capital at a reasonable rate.⁴⁴
- 8.27 UR said that it was also unlikely that any alleged cost of regulatory uncertainty would result in a higher cost of capital than was already reflected in PNGL’s 7.5 per cent rate of return.⁴⁵ UR said that for these reasons there were strong arguments for explaining to investors these particular circumstances and assuring them that UR was committed to the principles of best regulatory practice and allowing Northern Ireland regulated companies to finance their activities as UR had done since UR’s inception. UR said that its decisions in no way diminished its commitment to ensure that customers paid back in full the cost of efficient investment.⁴⁶
- 8.28 UR noted that there was no conclusive evidence that the premium for PNGL’s traded debt had widened to date and there was unlikely to be a longer-term effect of regulatory uncertainty on the cost of capital in Northern Ireland because there was no ‘market theory or academic evidence which would suggest markets would react several years after an event’.⁴⁷ UR also argued that the academic evidence regarding the impact of regulatory uncertainty on the cost of capital was ambiguous.⁴⁸

⁴⁰ UR [comprehensive response to draft proposal \(2012 decision\)](#), p12.

⁴¹ UR [supplementary submission](#), paragraph 1.11.

⁴² UR [supplementary submission](#), paragraph 1.11.

⁴³ UR [comprehensive response to draft proposal \(2012 decision\)](#), p19.

⁴⁴ UR [comprehensive response to draft proposal \(2012 decision\)](#), p12.

⁴⁵ We note that any effect could raise the cost of capital in the future beyond 2017.

⁴⁶ UR [comprehensive response to draft proposal \(2012 decision\)](#), p12.

⁴⁷ UR [response to provisional determination](#), paragraph 1.11.

⁴⁸ UR [response to provisional determination](#), paragraph 2.25.

Effect on other companies and industries

- 8.29 UR said that it had not seen any evidence to suggest that its proposals would have any impact on the perceived risks to the electricity and water industries, and indeed they were consistent with Great Britain precedents in their treatment of outperformance by its sharing with consumers.⁴⁹ It considered that the issues were unique to PNLG and were a one-off.⁵⁰ It had seen no expression of worries from credit rating agencies in regard to the other gas companies which UR regulated.⁵¹ It said that the stakeholders it had spoken to did not in any sense see any implications for other gas industry investments.
- 8.30 UR also argued that there was no evidence from PNLG that its decisions had negatively impacted investment in Northern Ireland and Great Britain. To corroborate this statement, UR cited that PNLG had subsequently expressed interest in expanding its distribution activities; other credit-rated gas companies in Northern Ireland had not been affected and investment in the gas industry was ongoing. For example, UR said that PNLG had made a discretionary investment in the network since the PNLG12 proposals were published and firmus had requested an additional £8 million of investment in 2012 to increase gas connections and extend its gas distribution network to the town of Bushmills. UR also submitted that BP applied for a Northern Ireland gas storage licence in 2012 and that Scottish and Southern purchased Phoenix Supply in July 2012 for around £20 million.⁵²
- 8.31 UR emphasized that its work on bringing Gas to the West of Northern Ireland had brought it into direct contact with multiple investors and not one had brought up the PNLG12 decision as a barrier to investment. UR argued further that some investors had ‘explicitly expressed no concern over it [ie PNLG12 decision]’⁵³ as they concur ... that the 2007 new licence represents exceptional circumstances and that the adjustment is “specific to the special situation of PNLG”.⁵⁴ UR said that four investors had expressed an active interest in the project.⁵⁵ It presented evidence (such as letters expressing interest in gas developments), although we thought these provided very limited evidence on this point as the expressions of interest were either at a very high and ‘in principle’ level, or did not refer to regulated sectors of the gas industry, or were somewhat qualified over concerns about regulatory stability. UR also said that there was no evidence of a spillover of regulatory uncertainty to regulated companies in Great Britain and none had responded to the CC’s call for submissions.
- 8.32 In response, PNLG said that neither it nor Terra Firma would proceed with an acquisition of firmus or expansion of the natural gas network outside PNLG’s existing Licensed Area while the current regulatory uncertainty caused by UR persisted.⁵⁶ It also said that the other gas companies which UR regulated were not similar to the regulatory and commercial model of PNLG (and that none of the other cases referred to involved gas distributors). It said that Mutual Energy (the owner of both Belfast Gas Transmission Limited and Premier Transmission Limited) was the only other gas company in Northern Ireland which had its own financing arrangements. As Mutual Energy was wholly underwritten by customers, it said that all costs (whether predict-

⁴⁹ UR [comprehensive response to draft proposal \(2012 decision\)](#), p5.

⁵⁰ UR [comprehensive response to draft proposal \(2012 decision\)](#), p2.

⁵¹ UR [supplementary submission](#), paragraph 2.151.

⁵² UR [response to provisional determination](#), paragraph 2.15.

⁵³ UR provided letters which convey investors’ expression of interest in expanding the gas network to the West of Northern Ireland. However, we have not seen unequivocal or ‘explicit’ statements to substantiate that investors are completely unconcerned about UR’s PNLG12 decision.

⁵⁴ UR [response to provisional determination](#), paragraph 2.16.

⁵⁵ UR [response to provisional determination](#), paragraph 1.9.

⁵⁶ PNLG [supplementary submission](#), paragraph 2.6.

able or not) were passed on to customers under its licence. PNGL said that Mutual Energy was only subject to shadow price regulatory control reviews and did not carry the risk of financing new investment or the penalty of cost overruns under its licence.⁵⁷

Evidence on effects on investment and cost of capital

- 8.33 We now summarize evidence from the rating agencies on how PNGL's and other utilities' credit ratings may be affected by UR's decisions. Evidence from other third parties is set out in paragraphs 8.53 to 8.74, and evidence from PNGL on its willingness to invest is set out in paragraphs 8.76 to 8.78.

Credit ratings agencies' views

Fitch Ratings

- 8.34 We considered the research published by Fitch with regard to the rating of PNGL. Fitch indicated that regulatory settlements had the potential to impact on PNGL's credit ratings. Indeed, Fitch noted that '... the key risk that PNG faces is regulatory risk'.⁵⁸

- 8.35 In its Key Ratings Drivers for PNGL,⁵⁹ Fitch noted not only that unfavourable settlements could reduce PNGL's credit rating, but that PNGL's price controls were likely to confer a higher degree of discretion for UR than for gas distribution networks in Great Britain. It said:

Inadequate tariff settlements or evolution of the regulatory regime could increase the sector's business risk and adversely affect the credit ratings ... While these rating drivers apply equally to gas distribution networks in Great Britain, the regulator in Northern Ireland cannot pursue as clear a benchmarking approach due to lack of comparables. Therefore, future tariff settlements are likely to involve a higher degree of negotiation, on a less transparent basis and with more discretion for UReg, than would be seen in GB.

- 8.36 Despite the concern in the preceding paragraph that UR may have more discretion in regulatory price setting than other Great Britain regulators, Fitch noted that the UR closely followed the approach of other Great Britain regulators like Ofgem, and that an increasing level of sophistication of the Northern Ireland economic regulatory regime was to be expected:

UReg operates with limited resources compared to the GB regulators, the regulatory framework is still at an early stage of development, and the regulator is therefore very interested in the progress and outcome of similar projects in other jurisdictions. For many aspects of Northern Ireland regulation, a replication of the GB Ofgem methodology and initiatives can be identified and UReg has confirmed that it is closely following the RPI-X@20 consultations. Generally, the agency expects

⁵⁷ PNGL [supplementary submission](#), paragraph 2.8.

⁵⁸ Fitch Ratings PNG Presale report, 16 October 2009.

⁵⁹ Fitch Ratings PNG Presale report, 23 November 2009.

ongoing evolution of the regulatory framework and the emergence of an increasing level of sophistication over time.⁶⁰

8.37 Similarly, Fitch affirmed that UR adopted the consultative stakeholder approach of other Great Britain regulators: 'The ratings reflect the regulatory environment in which PNG operates, which is still at an early stage of development but follows the consultative stakeholder approach pursued by British regulators.'⁶¹

8.38 Also, while reiterating that the regulatory framework for PNGL was at an early stage of development, Fitch indicated in 2010 (with a similar statement in August 2011, although this pre-dated publication of UR's PNGL12 consultation paper) that the Northern Ireland regime was similar to the Great Britain regime in terms of its supportive and transparent regulatory framework:

Gas distribution networks in the UK operate as regional monopoly service providers in supportive and transparent regulatory frameworks. The sector features low business risk and stable cash flow characteristics. Besides, revenue-profiling pursued by Ofgem and the Utility Regulator (Northern Ireland) has pushed out part of cash flow generation to future periods, while recognizing the deferred portion as part of the asset base. These are considerations that allow the three networks (ie, Scotland Gas, Southern Gas and PNGL) to support higher leverage than the average 'BBB' rated issuer.⁶²

8.39 In October 2011, Fitch placed Phoenix Natural Gas Limited's (PNG's) Long-term Issuer Default Rating (IDR) of 'BBB' and senior unsecured rating of 'BBB+' on Rating Watch Negative pending the outcome of the open consultation 'Phoenix Natural Gas Limited Price Control Draft Proposals 2012–2013' published by UR on 26 August 2011. Fitch noted UR's proposal for an £80.8 million reduction in TRV, with the comment:

Fitch understands that the retrospective clawing back of value for the benefit of customers is inconsistent with PNG's existing license dated 26 June 2009 and represents an unexpected change in Ureg's communicated regulatory approach. The regulator's move to propose a retrospective TRV adjustment relating to outperformance dating from the years 1996-2006 is not considered by the agency to be good regulatory practice.

We asked Fitch about the impact of this. Fitch clarified that the impact of the rating watch negative—which followed UR's draft proposals—would be likely to be crystallized as a one-notch downgrade of PNGL's IDR and senior unsecured rating in the event of a material TRV adjustment.

8.40 Fitch explained that the TRV adjustment came as a surprise. It said that it had been in discussion with UR since 2008, prior to issuing its first rating for PNGL. UR had not referred to the prospect of such an adjustment. UR had mentioned that it would be moving to a system of sharing outperformance, but Fitch had understood these comments to relate to prospective outperformance.

8.41 In October 2011, at the same time as Fitch placed PNGL's IDR on rating watch negative, the agency alluded to how this could impact on its wider perception of the

⁶⁰ Fitch Ratings PNG Presale report, 23 November 2009.

⁶¹ Fitch Ratings PNG Update, 28 June 2010.

⁶² Fitch Ratings PNG Update, 28 June 2010.

regulatory framework for gas distribution in Northern Ireland. Specifically, Fitch noted that:

As the agency considers transparency and predictability of the regulatory regime to be a key rating driver for gas distribution networks, the outcome of the draft proposals could have further implications for how Fitch views the regulatory framework for gas distribution in Northern Ireland.⁶³

8.42 In May 2012, Fitch removed PNGL's IDR and senior unsecured rating from rating watch negative. This followed UR's publication of Final Decisions which showed a slightly lower TRV reduction, slightly better cash-flow generation than initially forecast by Fitch, higher out-turn RPI, and that PNGL would not pay any dividends.

8.43 However, while removing the rating watch negative, Fitch maintained that the outlook on PNGL's Long-Term IDR was negative. It said:

The negative outlook is pending the outcome of the CC proceedings, and/or further evidence related to the development of the regulatory regime (including the assumptions and scope for dividends) for gas distribution networks in Northern Ireland, expected by the end of 2013 through the outcome of the price control review for the period 2014–2018.⁶⁴

8.44 In May 2012 Fitch also reiterated that its view on the 'predictability and supportiveness' of the Northern Ireland regulatory regime was subject to revision pending the outcome of the CC's determination and the 2014–2018 price control review. It said:

Given the retrospective TRV adjustment that includes a clawback of £59.6m of operating and capital expenditure outperformance, which is inconsistent with PNG's existing licence, Fitch could change its view on predictability and supportiveness of the regulatory regime in Northern Ireland and revise the applicable ratio guidelines for PNG's 'BBB' IDR.

8.45 However, Fitch told us that it did not anticipate an immediate reduction in the credit rating for PNGL in response to the TRV adjustment being made, as it expected to gather further evidence for its decision from our 2012 findings and from the price control review for the period 2014–2018.

Moody's Investors Service

8.46 In April 2012, Moody's published its analysis of the impact of UR's Final Decisions, and the subsequent referral of PNGL's price control determination to us.

8.47 Moody's analysis suggested that UR's Decisions would have little impact on PNGL's financial ratios, and therefore saw PNGL's credit rating as unaffected.⁶⁵ Specifically, Moody's assessed:

⁶³ Fitch Ratings PNG Press Release, 12 October 2011.

⁶⁴ Fitch Ratings, PNG Press Release, 2 May 2012.

⁶⁵ Moody's drew our attention to hypothetical situations which illustrated circumstances in which its credit rating could be affected, drawn from its 2012 report. It said:

Moody's notes, however, that had the regulator made the proposed adjustment to TRV prior to PNG's bond issuance in 2009, achieving a Baa2 rating would have been more demanding with a net debt/TRV ratio higher than 80%. In addition, Moody's notes that PNG's ultimate parent, Terra Firma, has so far not taken a cash dividend from the company since issuing the bond—a clear difference in approach versus many of the infrastructure-fund-owned network

Given the long-dated nature of the company's asset base and of the regulatory model for earning a return, UR's adjustment to TRV has only a minimal impact on near-term revenue and cash flow. Therefore, most cash flow ratios, including funds from operations (FFO)/interest, FFO/net debt and retained cash flow (RCF)/capital expenditure (capex) are only slightly affected. For net debt/TRV, while the adjustment is more significant (the ratio increases to the mid-60s in percentage terms from the mid-50s), PNG's current rating of Baa2 is based on the expectation that leverage will remain no higher than the low 70s in percentage terms, and is thus unaffected.

8.48 Moody's explained that it placed a high importance on the stability and predictability of the regulatory regime. Moody's also clarified that it currently scored the Northern Ireland framework at 'Aa', which was one notch lower than the Ofwat and Ofgem regimes in Great Britain. This was because while the framework broadly followed an RPI-X methodology, there was a one-notch differential which was largely explained by regulation being less established in Northern Ireland with a shorter track record of transparent decision-making. This one-notch differential also factored in a higher possibility of changes to the overall regulatory approach.

8.49 Following UR's Final Decisions, Moody's noted that there could be a perception of higher regulatory risk for PNGL notwithstanding the negligible impact on PNGL's financial ratios. This appears to be driven by Moody's perception that UR did not give sufficient notice of its proposed adjustments to the TRV, and hence has undermined the transparency and predictability of the regulatory framework. It stated:

Moody's believes, that major changes to either the form of the price control or to one of its key components (e.g., the TRV) should be well communicated and explained with sufficient time for consultation among relevant stakeholders. This increases both the transparency and predictability of the regulatory framework. If UR's position is that it always intended to make an adjustment to TRV, it is surprising that that was not communicated well in advance of the Initial Consultation Paper publication in August 2011. Given that the proposed amendments were introduced at such a late stage, Moody's believes that UR's actions fall somewhat short of transparent and predictable regulation. It could be argued, therefore, that UR's chosen approach has negatively impacted the perception of regulatory risk for PNG.

8.50 Moody's said that it intended to await the outcome of our redetermination before deciding whether regulatory risk for PNGL had increased. It said:

Moody's does note, however, that the right to ask for a Competition Commission referral is an integral aspect of the regulatory process in the UK. Moody's will therefore await the Competition Commission's re-determination before making any re-assessment of the transparency and predictability of the regulatory framework in Northern Ireland.

8.51 Warning of the possible impact of our determination on the future cost of PNGL's financing, Moody's remarked that in the event that 'the Competition Commission rules against PNG, it cannot exclude the possibility that its credit rating could be affected'. Moody's emphasized that it would take a balanced view, taking into

utilities in Great Britain. Hypothetically, if PNG's owners had opted to take a dividend to maintain a constant leverage (e.g., in the high 60s in percentage terms), the regulatory adjustment to TRV, if upheld by the Competition Commission, would likely have resulted in a 'trigger event' under the net debt/TRV covenant.

account headroom on PNGL's current credit metrics, together with Moody's view of the regulatory framework, following the outcome of the CC process.

Third parties' views

- 8.52 A number of third parties made submissions, including consumer bodies, infrastructure investors, market participants, trade associations and government departments, relevant to the issue of whether the proposed TRV adjustment for PNGL has undermined, or will undermine, the degree of regulatory certainty for investments in Northern Ireland. The submissions present divergent views on the potential for investment deterrence due to a TRV adjustment for PNGL. These submissions are summarized in the following paragraphs. We also received a number of third party submissions in response to our provisional determination, which are summarized in Appendix I. Because the points raised were largely similar, we report a summary of them in paragraph 8.75.

CCNI

- 8.53 CCNI has registered its concern, in principle, about regulatory uncertainty having an impact on incentives to invest, without proffering an opinion on whether such a disincentive is likely to materialize in practice. In this regard, it noted:

PNG has raised the prospect of the Regulator's proposals on adjusting the TRV as representing a threat to future utility infrastructure investment in NI ... If this is a fact then it will be a concern to consumers, although we do note that the Fitch release in October 2011 was commenting only on the NI natural gas industry ... Fitch Ratings issued a further Press Release on 2 May 2012, which removed PNG from Ratings Watch Negative.

In the absence of clear evidence, the Consumer Council is not in a position to assess the risk for consumers and we would ask that the Competition Commission considers this matter in detail ... If it is possible to do so, consumers in NI would benefit from firm assurance that the decisions made within the PNG Price Control will not raise the level of risk to all regulated utilities in NI to a level that on balance creates extra costs for them.⁶⁶

Martin N M Falkner⁶⁷

- 8.54 Mr Falkner has worked for Terra Firma in the past, and has experience of the regulated Northern Ireland industry. He stated that 'if the Commission were to support the Authority's position, it would likely raise doubts among infrastructure investors generally about the stability of UK regulation and the degree of protection afforded them by a reference to the Commission'.
- 8.55 Mr Falkner said that based on discussions with long-term infrastructure investors, the actions taken by UR had already created investor concern about the predictability and certainty of regulation in Northern Ireland. He added that his dialogue with infrastructure investors revealed that some already considered regulation in Northern Ireland too erratic to support long-term investment. Mr Falkner urged us to reject the

⁶⁶ Consumer Council [submission to the CC](#).

⁶⁷ Martin N M Falkner (of Gleacher Shacklock) [submission](#).

TRV adjustment so that Northern Ireland may continue to attract third-party investment in infrastructure, unless compelling evidence existed that such an adjustment was agreed as part of the 2006 'agreement' on the package of modifications.

8.56 Specifically, Mr Falkner cited the following concerns regarding UR's approach and determination:

- (a) UR had demonstrated at times a different culture and approach to regulation when compared with the Great Britain regulators.
- (b) UR appeared to favour announcing negotiated 'agreements' which lacked the process and transparency of typical price control decisions.
- (c) There could be long gaps between the announcement of a regulatory settlement and the implementation of licence amendments.
- (d) UR appeared to conduct fewer public consultations than the Great Britain regulators, and appeared to publish less data and analytical support for its conclusions than the Great Britain regulators. Rightly or wrongly, this created an external perception of less rigour in the Authority's decision-making processes.
- (e) In the current case, from an external perspective, the specific cost issues raised in the current price review appeared to have been identified by the Authority possibly as far back as 2004. Given the lack of further commentary by the Authority on the matter in 2006 and 2008, investors could reasonably be expected to assume that the issues had been fully resolved.
- (f) Whilst UR acknowledged in its 'Introduction to the Reference to the Commission' that there were shortcomings in its handling of this (and previous) determinations, it gave no weight to that acknowledgement in its assessment of the balance of the arguments. From the outside, it would appear that this may reflect that the Authority attached a different level of importance to regulatory certainty than Great Britain regulators.

*iCON Infrastructure*⁶⁸

8.57 iCON Infrastructure expressed concern over the potential impact on regulated assets in the UK due to the perceived retrospection of the adjustment to PNG's TRV. The submission stated:

Our attention has been drawn to the current investigation because of PNG's argument that elements of the Authority's proposed price control represent a retrospective change to, and an attempt to unwind, a settled element of the regulatory regime applying to PNG which will have major negative implications for PNG's debt and equity financing arrangements. If PNG's factual submissions are upheld, i.e. that element of the regime was considered settled—and I make no comment on the correctness of PNG's contentions—I would be concerned as to the possibility and implications of such regulatory action in a broader context (including the impact on regulation of the sector in Northern Ireland and, more generally, regulated assets in the United Kingdom).

⁶⁸ [iCON infrastructure submission](#).

... [if] the 2006 OAV set out in the licence was a settled figure, as PNG argue, then we would have serious concerns about attempts to amend its value on an ex-post basis. This would, for example, affect our willingness to invest in such a regulatory environment and we would expect that rational investors willing to invest in such circumstances would come from a class that demanded a higher return commensurate with their increased risk appetite.

Bryson Energy

- 8.58 Bryson Energy (a social enterprise that works to reduce fuel poverty by improving energy efficiency and by carrying out benefits checks) suggested that the underdevelopment of the gas industry in Northern Ireland stemmed from the ‘public perception that energy companies are operated for the benefit of their shareholders rather than regulated in the wider public interest’.⁶⁹

*North Ireland Independent Retail Trade Association*⁷⁰

- 8.59 North Ireland Independent Retail Trade Association (NIIRTA) highlighted that the continued expansion of the natural gas industry was critical so that a greater proportion of Northern Ireland’s commercial and domestic customers could benefit from the social, economic and environment benefits that natural gas could deliver. The submission cited that the Northern Ireland Executive was currently trying to attract inward investment into Northern Ireland which remained heavily reliant on public sector employment, which was not sustainable. Therefore, if the proposals by UR had the potential to impact negatively upon future infrastructure investment in the Northern Ireland energy industry, then this would be of concern to NIIRTA.
- 8.60 NIIRTA was concerned that if PNGL’s cost of borrowing increased in the future as a result of the proposed price control actions, then consumers and businesses might ultimately pay for this in the longer term. NIIRTA said that while the proposed savings stated by UR were welcome, it urged us to balance these savings with a longer-term, more strategic view of the potential negative implications that had been flagged up by both PNGL and global ratings agencies.

Manufacturing NI

- 8.61 Manufacturing NI, while generally supportive of UR’s proposals, urged us to have regard in its judgement to ensuring that in future a stable environment existed for the regulation of utility infrastructure.⁷¹

Age NI

- 8.62 Age NI noted ratings agencies’ and PNGL’s concern regarding the negative impact that UR’s decisions would have on infrastructure investment. Age NI questioned why, if it was vital for PNGL to undertake network investment in the West of Northern Ireland, it had not already undertaken such investment to date. Age NI suggested that it was opportunistic to now cite investment deterrence as a part of PNGL’s case

⁶⁹ Bryson Energy [submission](#).

⁷⁰ NIIRTA [submission](#).

⁷¹ Manufacturing NI [submission](#). We understand that Phoenix is an Associate Member of Manufacturing NI.

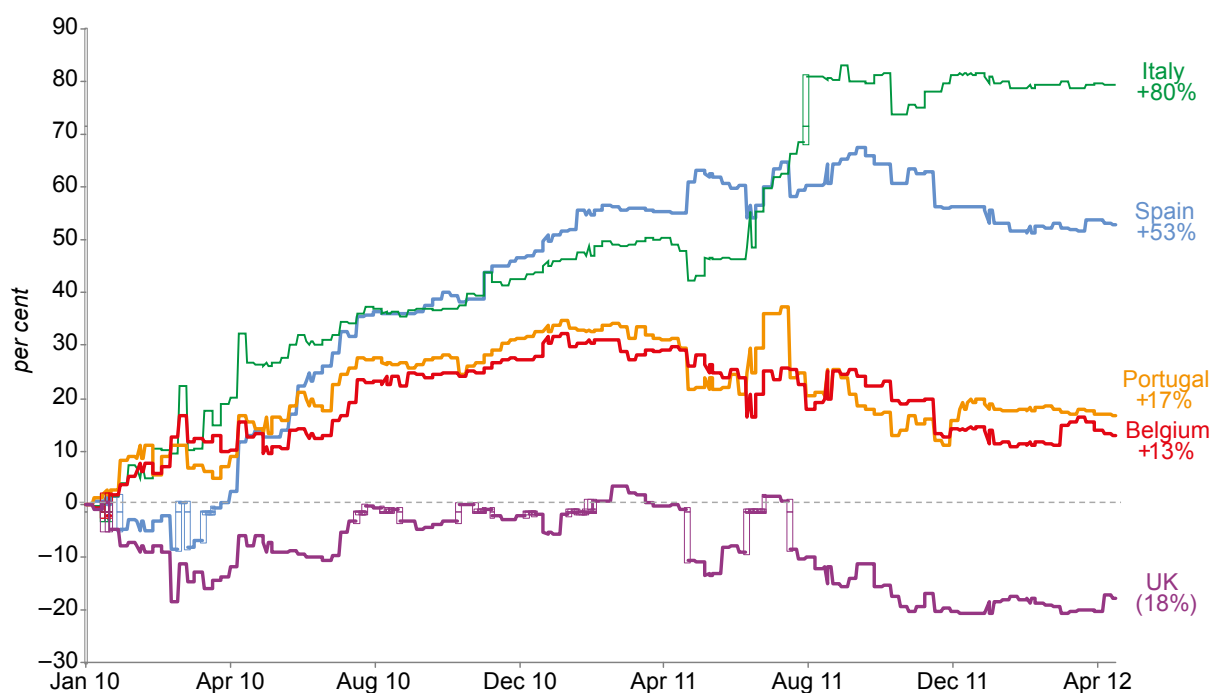
to resist UR's proposed amendments, when there did not appear to have been a clear inclination to undertake this investment in the first place.⁷²

*J P Morgan*⁷³

- 8.63 J P Morgan submitted that regulatory uncertainty could have a demonstrable impact on increasing the perceived risk of a regulated company. It looked at market evidence for regulated utilities in environments which were perceived to have higher regulatory risk, relative to those where there was a perception of low regulatory risk.
- 8.64 It estimated that in the past year, as the regulatory environment in Spain and Italy was perceived to be uncertain, there had been a 116 bps increase in CDS for Red Electrica and a 76 bps increase in CDS for Snam Rete Gas. On the other hand, National Grid and United Utilities, which benefited from a more stable regulatory environment, had seen their CDS reduced by 25 bps and 8 bps respectively.
- 8.65 Similarly, J P Morgan estimated that equity betas for European utilities had risen or declined in accordance with the perception of regulatory uncertainty over the past couple of years, as shown in Figure 8.2.

FIGURE 8.2

Evolution of equity betas of regulated utilities since 2010



Source: J P Morgan.

Note: Betas calculated as one-year historic regression vs the Euro Stoxx 50 based on weekly observations. Regulated utilities: Spain (Red Electrica, Enagas), Italy (Terna, Snam), Belgium (Elia, Fluxys), Portugal (REN), UK (National Grid, Severn Trent, United Utilities, Pennon).

⁷² Age NI submission.

⁷³ JP Morgan submission.

DETI^{74,75}

- 8.66 DETI said that the key document in relation to energy policy in Northern Ireland was 'The Strategic Energy Framework 2010'.⁷⁶ DETI's submission highlighted the importance of developing the gas industry of Northern Ireland, and the significant benefits provided by natural gas in terms of lower energy costs and reduced carbon emissions. As such, the Northern Ireland Executive had a key target to work with UR and the gas industry to extend the provision of natural gas to new areas of Northern Ireland.
- 8.67 During 2011, DETI consulted on the merits of extending the gas network in Northern Ireland, and planned to have the gas network extended to new areas such as the West of Northern Ireland and to towns in East Down. However, DETI noted that gas network extension would take time, requiring a number of actions over the next few years including the award of licence(s), network design, environmental considerations and planning consent before new gas mains are installed.
- 8.68 In this context, DETI's submission highlighted that 'the development and maintenance of an overarching business environment which is attractive to investors, both indigenous and international, and across all sectors, is crucial—especially in the current economic climate'.
- 8.69 DETI recognized that given the scale of investments made by existing, and future, investors in the energy market, an important element was the delivery of a stable regulatory environment, consistent with good practice elsewhere in the UK. This sent appropriate signals not only to the players in the energy domain, but also to investors in the wider economy.
- 8.70 DETI's submission does not comment on whether UR's decision would deter investment by companies in Northern Ireland in practice. DETI recognized the importance for PNGL (and other energy providers) of making acceptable returns on their investments, and that such returns were sufficient to allow for both ongoing and further investment.
- 8.71 In responding to the provisional determination, DETI reaffirmed its commitment to gas network extension in Northern Ireland where it was technically possible and economically feasible. DETI indicated that it had been in discussion with companies in the West of Northern Ireland to whom natural gas is not currently available, but whose competitiveness would increase should the gas network expand to the West of Northern Ireland. DETI stated that it 'will continue to focus on extending the natural gas network in Northern Ireland, though engaging with the Utility Regulator, the energy industry, other government Departments and Agencies, and energy consumers'.

*Northern Ireland Electricity*⁷⁷

- 8.72 Northern Ireland Electricity (NIE) expressed serious concern over UR's decision retrospectively to adjust PNGL's TRV. It said that its concerns arose because the integrity of a company's regulatory asset value was critical to the integrity of the entire regulatory regime. Retrospective adjustments like this conflicted with good regulatory practice which promoted consistency, predictability and transparency in

⁷⁴ DETI submission.

⁷⁵ DETI response to provisional determination.

⁷⁶ www.detini.gov.uk/strategic_energy_framework__sef_2010_-3.pdf.

⁷⁷ NIE submission.

regulatory decision-making. It said that such adjustments were contrary to the interests of customers because they increased investors' perceptions of regulatory risk, thereby increasing the cost of capital.

- 8.73 It noted that the cost of bonds issued by both NIE and Phoenix was higher than the cost of bonds issued by Great Britain gas and electricity utilities, which it said was evidence that the capital markets already perceived a higher risk of investing in Northern Ireland. NIE said that it had recent experience of raising bond finance and it could not emphasize too strongly the importance of consistency, predictability and transparency within the Northern Ireland regulatory model.

*firmus energy*⁷⁸

- 8.74 firmus said:

the development of an efficient, economic and co-ordinated energy network requires investment in long term assets. Financing this investment efficiently requires that regulation is predictable and objective. ... If regulation is not stable and predictable, investors will be uncertain as to the level of future returns. As a result, they will add a premium to the return required to make long term investments to cover the possibility that regulation changes in an unexpected manner and leaves them unable to cover efficient costs ... NI energy investments are principally rewarded through a regulatory asset base. The Utility Regulator determines an efficient level of investment over time (which is included in the asset base) and a reasonable return on investments (the WACC). Once investments are approved by the Utility Regulator, investors should and do expect a return to accrue over the agreed asset life ... Changes which look to undermine the confidence of investors in securing a return on a regulatory asset value agreed by a Regulator are particularly important, as they undermine a concept which is key to efficient long term financing.

Additional third party points raised in response to the provisional determination

- 8.75 We received responses to the provisional determination from a number of third parties. These are summarized individually in Appendix I, but we note that many of them made broadly similar additional points, relating to our assessment of regulatory uncertainty and its impact on the cost of capital and/or future investment in Northern Ireland. Therefore these are summarized below:

- (a) A number of submissions noted that there had been recent developments in the gas market in Northern Ireland while the CC process had been ongoing, such as the sale of PNGL's gas supply business to Airtricity in June 2012, and firmus' extension to build beyond its licensed area into Bushmills. There had also been an expression of interest from several companies regarding possible expansion of the gas network to the West of Northern Ireland.
- (b) A number of submissions noted that there was a dearth of quantitative evidence regarding the extent to which there was a perception of regulatory uncertainty in Northern Ireland, and the impact this had on the cost of capital and investment decisions.

⁷⁸ firmus [submission](#).

- (c) Several third parties questioned the extent to which there would be heightened regulatory uncertainty were UR's PNG12 decision to be fully implemented. Parties also questioned whether there would be an impact of heightened regulatory uncertainty in the future which had not been captured by market developments to date.
- (d) A number of parties questioned the weight which should be afforded to potential outcomes. For example, one submission argued that the public interest might be better served if short-term prices for gas customers were definitely reduced now, while any resultant uncertain 'regulatory risk premium', should it arise, was included in transmission costs that would be postalized across all users of the gas network in Northern Ireland.

PNGL's submissions on its own willingness to invest

- 8.76 PNG12 said that the TRV adjustment would impact on the investments it would choose to undertake. It said that it had undertaken discretionary investments since 2006. For example, based on the 2006 'agreement' on the package of modifications, PNG12 applied for, and was awarded, a licence extension to make gas available to Comber, Temple Quarry and McQuillan Quarry. It said that significant investment had been made in making gas available to, and connecting, customers in Comber and also the two large quarry customers. It told us that this additional, discretionary investment would not have been made in the absence of the 2006 'agreement' which PNG12 had believed to have established a fixed TRV. It also noted that it had by the end of 2011 rolled out the gas network to be available to around 292,000 properties (88 per cent) of the properties within its Licensed Area, whereas the Mandatory Development Plan required PNG12 to make gas available to only 81 per cent (ie around 24,000 more properties than required by its licence). It said that had PNG12 believed that the basis on which it was to be incentivized and earn a return might be significantly revisited, it would have carried out a very different review of discretionary investment. PNG12 also said that it would struggle to convince its investors to undertake any additional, discretionary investment in the future, eg taking gas to the West and South or acquisition and development of firmus if UR was allowed to make unexpected retrospective adjustments to PNG12's TRV as soon as the cash flows being generated were sufficient to allow such interventions without impacting the forward-looking financeability of the company.
- 8.77 PNG12 said that its interest in expanding its current Licensed Area and/or proactively seeking to cover the 40,000 properties within its current Licensed Area that did not have gas available (where connection would be expected to be more costly than the average cost of constructing the infill network to the currently served properties) was critically dependent on it having reasonable confidence in an ability to earn a return through efficient investment (ie to participate in an activity subject to the normal rules of incentive regulation).
- 8.78 PNG12 said that its interest was significantly tempered by UR's actions which eroded PNG12's confidence in investing; and revisiting previously agreed principles underscored for PNG12 the riskiness of the Northern Ireland system of regulation. It said that concern over returns, retrospective adjustments and riskiness could limit both the prospects of efficient financing and acceptable returns.
- 8.79 As noted in paragraph 8.30, UR argued that PNG12 had extended its network since the PNG12 proposals were published.⁷⁹ UR notified the extension of PNG12's

⁷⁹ UR [response to provisional determination](#), paragraph 2.15.

licence area towards the end of March 2012.⁸⁰ UR indicated that this was evidence that investment in the gas industry in Northern Ireland had not been deterred by the PNG12 decision. PNG12 responded by telling us that it had applied for a small licence extension (to serve a single commercial customer), amounting to £25,000 in July 2011, ie before the PNG12 draft determination by UR was published. PNG12 said that it proceeded to make the licence extension once this had been approved, due to the small size of the investment, and because it had already committed to provide gas to the customer.

Assessment

- 8.80 PNG12 said that UR's proposals were retrospective and had implications for regulatory uncertainty, and undermined investors' confidence in the regulatory environment. It said that this would discourage investment, and risked increasing the cost of capital, in particular for greenfield projects but also for other Northern Ireland utilities, thus making future expansion of the gas system less likely to occur and/or more expensive.
- 8.81 UR said that any effect would be small in comparison with the value of the TRV adjustment. It said that investors would understand that this was a one-off starting point adjustment relating to monies the company had not spent and therefore this would not increase risk in the future, and there should be no impact on other regulated companies in Northern Ireland, or elsewhere. It said that the regulatory framework was supportive and that any alleged effect on the cost of capital would be unlikely to result in a figure higher than PNG12's current allowed rate of return of 7.5 per cent.
- 8.82 In our assessment we concentrate on the potential effects of UR's proposed TRV adjustment on regulatory uncertainty, willingness to invest and on the cost of capital. We consider these issues in relation to PNG12 and in relation to other utilities in Northern Ireland.
- 8.83 We see the main possible mechanisms by which willingness to invest and the cost of capital may be detrimentally affected by the proposed 2012 TRV adjustment as follows:
- (a) The ratings agencies may view the regulatory regime as less favourable and, as a result, may demand higher credit metrics for a given credit rating, which may lead to a downgrade of a company's debt. This may have the effect of decreasing the amount of debt that a company can have in its capital structure and/or increasing the cost of the company's debt, both of which could lead to an increase in the overall WACC.
 - (b) Equity investors may view the regulatory regime as less favourable, and as a result may increase the return that they require for investing in a given project. This may have the effect of increasing the required rate of return, in particular for greenfield investments.
 - (c) A perception of regulatory uncertainty may deter investment, on the margin, if companies are unable to form judgements or are very uncertain of what the regulatory environment will be and if, how or when they will receive a return on investments.

⁸⁰ UR [notice of extension to the licence area of PNG12](#).

- 8.84 The remainder of our assessment is structured as follows: first, we discuss the factors contributing to regulatory uncertainty and the extent to which they might apply in this case; secondly, we discuss the possible implications for investment and the cost of capital.

The extent to which regulatory uncertainty may arise

- 8.85 The evidence that we received, in particular from the ratings agencies but also from other interested parties, suggested that the stability, predictability and transparency of the regulatory regime was important to investors.
- 8.86 At UR's admission, it did not make its intentions clear in 2006 in relation to the treatment of outperformance included in the 2006 TRV (see paragraph 5.65). Neither did it make its intentions clear in the run-up to PNLG's debt issuance programme in 2009: Fitch told us that when it met with UR in 2008, the prospect of adjustments to the 2006 TRV in respect of past outperformance was not raised. Whilst UR raised the prospect of the adjustments in its August 2011 consultation paper, this was after a considerable time had elapsed after the 2006 discussions and the 2007 price control review and does not support UR's position that this was always something that it intended to revisit (see paragraphs 5.73 to 5.88). Therefore we can understand why investors may have had an expectation that the outperformance in the 2006 TRV would remain untouched, and may have been surprised by UR's proposal.
- 8.87 The evidence from stakeholders (see paragraph 8.52 onwards) suggests that the rationale for the proposed adjustment to the TRV was not widely understood and that the adjustment was perceived by investors to be retrospective in nature, because it involved a reduction in the TRV that had apparently been agreed in 2006. In these circumstances, we consider that it was particularly important for UR to ensure that its proposals and the rationale for these proposals were clearly set out and well understood by investors. It is not clear to us that UR communicated its rationale for making the adjustment in a sufficiently transparent manner to allow investors fully to understand its actions.
- 8.88 We note that prior to any announcement about the adjustment, both ratings agencies rated the Northern Ireland regulatory environment as following the consultative stakeholder approach pursued by Great Britain regulators, albeit it was at an early stage of development and therefore some minor differences may have been expected; however, we think it unlikely that the ratings agencies anticipated adjustments of the nature and size of the 2012 proposed TRV adjustment.
- 8.89 We expect that this would lead to a perception of regulatory uncertainty, as investors may assume that UR's future actions could be unpredictable. We do not agree with UR that investors will recognize this as a one-off decision because of the particular circumstances in hand that has no wider ramifications (in particular, because the ratings agencies told us that their assessment of the regulatory regime would take account of the regulator's past decisions). Investors may anticipate that in addition to normal commercial risks there could be greater uncertainty in the future about the regulatory environment, and thus increased risks that returns on investment will not be realized in the way or to the extent that is expected. This is likely adversely to affect investment decisions in the future.
- 8.90 We have considered UR's argument that there is ambiguous empirical and academic evidence to support the intuition that heightened regulatory uncertainty could increase the cost of capital. However, we note that both Fitch and Moody's take the predictability of the regulatory regime into account when setting credit ratings, hence we consider that there is clear effect on the cost of debt. The effect on the cost of

equity is harder to establish, but it is our view that unpredictability increases risk for equity investors and that this may increase beta and may also increase any asset stranding premium.

The effect of an increase in regulatory uncertainty

- 8.91 We now consider the potential effects of an increase in regulatory uncertainty. First, we first discuss the investments that could potentially be impacted; secondly we consider the quantum of the effect. From the evidence provided by Fitch and Moody's, we understand that an immediate downgrade of PNGL's debt is unlikely to occur because there is headroom in the credit ratios, and the agencies said that they would take a view following our decision and the next UR price control decision for 2014–2018. Hence we consider that the effect of increased regulatory uncertainty may not be felt immediately by PNGL but may have longer-term effects.
- 8.92 We think that this demonstrates that there could be an increased risk of a downgrade of the ratings agencies' assessment of the quality of UR's regulatory regime. A negative assessment of the regime could prevent an increase in the credit rating for PNGL, or possibly trigger a credit rating downgrade for PNGL. This may result in a cost of debt that is higher than it would otherwise have been.
- 8.93 Given the evidence from the rating agencies, we also think that this effect may extend to other utilities that are regulated by UR. This is because perceptions of the regulatory environment for other companies (even in non-gas sectors) are likely to be influenced by the observed behaviour of UR in this context. Therefore, the ratings of these utilities may also be reviewed if the ratings agencies revised their assessment of the stability of the regulatory regime downwards.
- 8.94 Aside from the potential effect on the cost of debt, we also consider that the cost of equity is likely to be impacted. This could apply equally to existing equity investments in utilities that are regulated by UR as well as future greenfield investments that fall under UR's remit.⁸¹ We also think that any effects on the cost of equity could be long-lived because the investment community may be expected to take into account UR's track record over a relatively long time period when investing in infrastructure assets with a similarly long life.
- 8.95 We have considered the arguments presented by UR and third parties that there is no evidence of investment deterrence as investments in the Northern Ireland gas industry have been ongoing since our inquiry began. For example, UR stated that BP, Scottish & Southern, firmus and PNGL had made investments in Northern Ireland since UR's proposals for PNGL were published.⁸² However, we do not consider that an increase in the cost of capital would necessarily halt investment but it would make it more expensive. This could mean that certain projects, that are marginally viable today, may no longer be viable in future. To that extent, we consider that an increase in the cost of capital may, at the margin, deter investment.
- 8.96 Further, we cannot rule out the possibility that investors take into account the CC's role in the regulatory regime. This corresponds with what we have been told regarding ratings' agencies and other stakeholders who are reserving judgement on the predictability of the Northern Ireland regime until after our process has been concluded.

⁸¹ We note that UR told us that plans for future network development in the West of Northern Ireland would be likely to see a RAB-based model with sharing of outperformance and a possible profile adjustment system over a period of 30 to 50 years, which has obvious similarities to the system that now applies to PNGL.

⁸² UR [response to provisional determination](#), paragraph 2.15.

- 8.97 In summary, we do not see merit in UR's claim that its actions would not have a large and prolonged impact on investor confidence because any increase in the cost of capital is already covered by the 7.5 per cent rate of return afforded to PNGL until 2016. We consider that a higher degree of uncertainty could impact on investor confidence in Northern Ireland in the longer term beyond 2016 and more generally (ie not only for PNGL), reducing the willingness to invest and/or increasing the return required to undertake investment in Northern Ireland.
- 8.98 We have considered UR's modelling of the impact of regulatory uncertainty on the cost of capital. We do not agree that it is possible to undertake any meaningful analysis to illustrate the impact of regulatory uncertainty in Northern Ireland, in particular the duration and quantum of any increase in the cost of capital are very hard to predict with any confidence, and it does not show any effects on the extent or timing of future network expansion. Therefore we do not consider that we can make a useful assessment within a cost-benefit-type framework (netting benefits to customers from lower prices from a reduced TRV against effects on the cost of capital and network development). We note that UR's cost-benefit analysis does not consider the possibility of an impact of regulatory uncertainty outside the gas industry. However, as stated in paragraph 8.93, we think there could be an impact across regulated utilities in Northern Ireland, not just the gas industry, especially given the cross-utility nature of the regulatory regime in Northern Ireland. Indeed, when UR argued that there was no evidence of investment deterrence in Northern Ireland to date, it had not focused on investment in the gas industry, but across regulated utilities.⁸³ This accords with our understanding that if marginal investment is deterred and/or takes place at a higher cost due to regulatory uncertainty, then this would not only impact on the gas industry but on other regulated utilities in Northern Ireland and on future greenfield investments.
- 8.99 Whilst we cannot forecast the size or duration with accuracy, it is our judgement that these effects could be significant. As an illustrative example, applying a 50 basis point uplift to the cost of capital to NIE's and PNGL's combined RABs of approximately £1.8 billion would equal £9 million a year. This does not take into account any effects on other regulated investments and on future greenfield investments.

Evaluation of evidence on premium for PNGL's debt

- 8.100 We have carefully considered the evidence presented by PNGL regarding the cost of its debt (see paragraphs 8.17 to 8.20 and Figure 8.1), which it said indicated that its bonds and NIE's⁸⁴ bonds traded at a significant premium to Great Britain comparators, and PNGL's view that this may be, in part, 'a Northern Ireland-specific effect, or be a reflection of the relatively more risky regulatory environment in Northern Ireland'. PNGL said that this premium had been observed since the issuance of PNGL's bond (see paragraph 8.102 for a description of the bond issuance), and had tended to grow since then.
- 8.101 We note that all but one of the bonds shown in the evidence from RBS, submitted by PNGL, have a higher Moody's rating than PNGL's Baa2 rating—even where the Fitch rating is equivalent at BBB+.⁸⁵ This difference in ratings may partly explain the observed differential in spreads.

⁸³ UR [response to provisional determination](#), paragraph 2.14.

⁸⁴ NIE is also a Northern Ireland utility regulated by UR.

⁸⁵ The exception is South East Water which also has a Baa2 rating.

8.102 We have looked at a number of debt issuances by Great Britain utilities in 2009 to assess the extent to which PNGL's yields are higher than comparable debt issues, and whether there has been a relative increase in PNGL's yields due to UR's decision. We have also considered evidence from PNGL on this. We have looked for bonds which are as closely matched as possible to PNGL's BBB+/Baa2, around eight-year duration, £275 million, 5.5 per cent bond issued in October–November 2009.⁸⁶ On the basis of these comparator criteria we have assessed:

- (a) The closest comparator bond to PNGL is a BBB+/Baa1, nine-year, £300 million, 5.125 per cent issuance by Southern Gas Networks which priced within a fortnight of PNGL's bond.⁸⁷
- (b) We have also included a comparator BBB+/Baa1, six-year, £300 million, 6.75 per cent issuance by ENW Capital which priced a few months before PNGL's issuance in July 2009.
- (c) We have included a comparator, as suggested by PNGL, which was not rated by Fitch at issuance, and had a higher Baa1 Moody's rating, but was compatible with our other criteria. This was a seven-year, £200 million, 5.125 per cent issuance by Wales & West in November 2009.

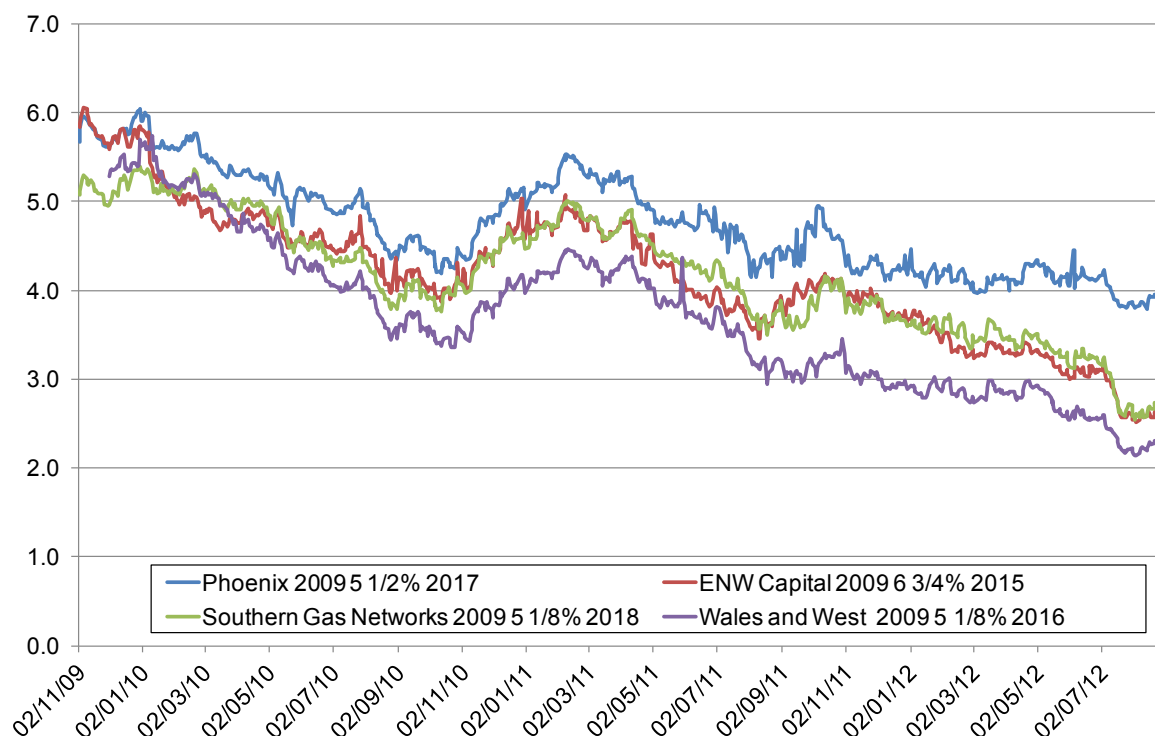
8.103 The difference in yields for these bonds, relative to PNGL, is shown in Figure 8.3.

⁸⁶ Our criterion for sample selection is: fixed-rate, GBP-denominated corporate bond issuance by utilities in 2009, with a maturity of five–ten years, proceeds of less than £300 million, and a Fitch rating (launch) of BBB+. There are no bonds which fit this criterion and which also had an equivalent Moody's rating to PNGL, ie Baa2. Source: CC and Oxera analysis of data from Dealogic.

⁸⁷ Source: CC and Oxera analysis of data from Dealogic.

FIGURE 8.3

Yields for PNLG bond since issuance relative to other Great Britain utilities



Source: CC and Oxera analysis based on data from Thomson Datastream and Dealogic.

- 8.104 This figure suggests that over the whole period since PNLG’s debt issuance, the yield has been about 70 bp higher than the comparator bonds. The differential in yields averaged about 60 bp before August 2011 and about 100 bp after August 2011. This suggests that the yields have widened by about 40 bp since August 2011.
- 8.105 We considered whether this provided evidence of an effect on the cost of debt arising from the regulatory regime in Northern Ireland, and also whether there was an effect resulting from UR’s consultation and decision on PNLG’s TRV adjustment.
- 8.106 We note the difficulty in benchmarking PNLG’s debt issue—for example, all the comparator bonds identified have a higher Moody’s rating, even where the Fitch rating is equivalent. This difference in ratings may partly explain the observed differential in spreads.
- 8.107 However, we cannot rule out the possibility that the differential in yields is due to specific features of the PNLG bond which we cannot readily observe in the market data. For example, we have noted comments from market participants at the time of PNLG’s debt issue which suggest that the market took into account unique features of PNLG in pricing the bond: ‘There are no real direct comparables for Phoenix in terms of pricing. It carries a slight premium to the sector—and also this is potentially because of the ownership structure.’⁸⁸

⁸⁸ Bookrunner comments, reported on Dealogic, for ‘Phoenix Natural Gas Finance plc; Corporate Bond-Investment-Grade—GBP275,000,000; Priced Wednesday, 28 Oct 2009’.

- 8.108 Similarly, we cannot rule out the possibility that any widening of the differential is due to other factors, such as general uncertainty coinciding with any price control decision, rather than due to a different perception of regulatory stability. We note that PNGL's evidence from RBS is also tentative in attributing an increase in spreads to UR's decision. Specifically, RBS argued that it was 'difficult to determine whether the Utility Regulator's Final Decision published in January 2012 has materially affected PNG's spreads to date'.
- 8.109 Nevertheless we consider that the differential in bond yields, and the widening of that differential since August 2011, may be partly due to Northern-Ireland-specific factors including the regulatory regime. We also think that there is a risk that further effects may be felt in the longer term (see paragraph 8.91).

Effect on regulatory uncertainty of a change in the rate of return

- 8.110 We now consider the potential effects on regulatory uncertainty and the cost capital arising from a reduction in PNGL's rate of return. We note that the rate of return of 7.5 per cent was written into PNGL's licence in 2007 and was stated as being fixed for a period of ten years until 2016.
- 8.111 UR did not propose any adjustment of that rate in making its final decisions on the PNGL price control in January 2012. In its submission to the CC,⁸⁹ it explained that its decisions were taken as part of a balanced assessment of the Price Control Conditions against the principal objective and general duties in which the continuation of the rate of return was a relevant factor. It said that since its proposals had been rejected, the rate of return would remain a relevant factor in considering whether a continuation of the revenue allowance that was currently permitted by those conditions was contrary to the public interest.
- 8.112 We observe that the rate of return is, like the RAB, highly important to investors as it provides assurance that investments made will be recovered over time at an interest rate that appropriately rewards risk. We note that Fitch in its pre-sale report of October 2009 makes several references to the rate of return of 7.5 per cent and the provision in the licence that this is fixed until 2016.
- 8.113 For these reasons we consider that our assessment of the effects of a change to the TRV on regulatory uncertainty and the cost of capital is equally relevant to a change in the rate of return. In summary, we consider that in circumstances where statements have been made to the effect that the rate of return would be fixed for ten years, and where the regulator has taken no action to signal that it wished to revisit the rate of return (other than in the context of the reference to the CC), the effect of changing that rate of return would have adverse affects on regulatory certainty and the cost of capital and these affects could have significant consequences for investment in Northern Ireland, in the gas industry and other regulated utilities in Northern Ireland and on future greenfield investments in Northern Ireland.

⁸⁹ UR [supplementary submission](#), paragraph 1.29.

9. Evaluation and findings

Introduction

- 9.1 In this section we state our findings on the public interest and make our determination on necessary changes to the licence.
- 9.2 UR has made a reference to the CC under Article 15 of the Gas Order¹ for the CC to investigate and report on two questions:
- (a) whether the Price Control Conditions operate or may be expected to operate against the public interest, and
 - (b) if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the conditions of the Licence.
- 9.3 UR states in the reference that ‘for the purpose of assisting the Commission’,² the ‘payment by gas consumers in Northern Ireland of higher prices for the conveyance of gas by PNGL than are necessary or appropriate’ are the matters that operate against the public interest. UR states that this is detrimental to the interests of consumers and to the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland.
- 9.4 The current price controls are in Part II of PNGL’s licence. In considering whether, without modification, they will or may be expected to operate against the public interest, the CC is required by Article 15(8) of the Gas Order ‘to have regard to the matters as respects which duties are imposed on the Department and [UR] by article 14 of the [2003 Order]’. These duties are set out in Appendix B.
- 9.5 We have applied the public interest test with due regard to the duties imposed by Article 14 of the Gas Order and Article 40 of the Gas Directive.
- 9.6 Our investigation, during which we have considered and investigated a wide range of issues, including the evidence of UR’s 2012 determination, has led us to conclude that the following issues are those that are of most concern for us and require investigation to determine whether they operate or may be expected to operate against the public interest:
- (a) the amounts included in the TRV in respect of opex and capex outperformance, and deferred capex; and
 - (b) the rate of return that PNGL should recover on its investment.
- Those two issues accordingly occupy the balance of this section. We have also considered a number of secondary issues, in particular whether PNGL has been funded twice for the same expenses in respect of business rates.
- 9.7 However, whether the existing price controls do contain matters which are contrary to the public interest does not turn only on our conclusions on these issues. There are

¹ As noted in paragraphs 3.11–3.15 and set out in Appendix A.

² Under Article 15(4) of the Gas Order, UR may specify: ‘(a) any effects adverse to the public interest which, in his opinion, the matters specified in the reference ... have or may be expected to have; and (b) any modifications of the relevant conditions by which, in his opinion, those effects could be remedied or prevented.’

further issues that are not in dispute between UR and PNGL as to whether the price controls need some modification, and which, after examination, are in our view rightly not in dispute. We set out our conclusions on all of these matters below.

9.8 In this section we address in turn:

- (a) opex and capex allowances and other matters where UR and PNGL were in agreement on the appropriate approach;
- (b) rate of return;
- (c) outperformance;
- (d) deferred capex;
- (e) 1999/2000 capex deferrals;
- (f) arguments as to why leaving the TRV unamended is not in the public interest;
- (g) conclusions on whether outperformance should be removed from the TRV; and
- (h) proposals to remove elements of the TRV and other actions to reduce prices.

Background

9.9 We make our determination in a context very different from that of normal utility regulation. Most regulated utilities consist of assets which are well established and for which, in the main, only replacement investment is needed and where expansion of the network is modest. The major financial and engineering risks have already been taken. By contrast, and perhaps uniquely, gas distribution is not yet a fully developed and mature industry in Northern Ireland. Indeed, the distribution network is still developing and important challenges for its development lie ahead. The history of the regulation of PNGL, which has figured large in the submissions made to us during our investigation and which has been an important element in our deliberations, reflects the uncertainties and difficulties of regulating a start-up business in which very heavy capital investment is required in order to make returns which will accrue only in the long term. PNGL's revenues have only recently started to exceed the cost of its operations and investment in building the network, and it is still recruiting customers (around 50 per cent of domestic properties with access to natural gas within PNGL's Licensed Area have converted to natural gas, and around 60 per cent of industrial and commercial properties—see paragraph 4.8).^{3,4} While the regulatory regime is now, post-PC03, increasingly similar to the regulation of a mature utility, a number of the issues that arise in our inquiry are a legacy of the initial development of the network and its regulation, while the continuing development of the gas distribution network in Northern Ireland is also an important context for our decisions. We see the context in which the current price control is set as a broad one, encompassing the creation and development of the distribution network that has been delivered so far, together with the remaining and not inconsiderable challenges in rolling out the remainder of the network, as well as ensuring fair prices for customers now. The

³ Because natural gas is likely to be cheaper than alternative fuels, we would expect that it would be the fuel of choice in most circumstances and so the level of take-up would be very high. We note evidence from DETI: 'There is widespread acceptance of the benefits of natural gas compared to other more polluting fuels such as oil and coal, and these benefits include cost savings, greater convenience and budget management for domestic consumers in particular ...'—see paragraph 4.54.

⁴ We also note that PNGL has never paid a dividend to its investors (although this is something within its discretion and investors may also realize a reward through the market value of PNGL).

considerations that have enabled PNGL to achieve what has been done so far remain important factors in the regulation of PNGL.

- 9.10 The novelty of the situation presents us with a more complex set of considerations than is normally the case. UR believes that the overall 2007 regulatory determination and the associated framework have led to gas distribution prices that are now too high, due principally to the inclusion of elements of deferred capex and historic out-performance in the TRV. It is not contentious to say that removal of those elements of the TRV would lead to a reduction in prices for domestic consumers and industrial and commercial (I&C) users. However, whether their continued inclusion in the TRV operates or may be expected to operate against the public interest is another matter. These items date from the early period of PNGL's activities in developing the network between 1996 and 2006, and they have been capitalized into the TRV because PNGL was unable to recover revenues to reward it for outperformance at the time. In UR's view their continued inclusion is contrary to the public interest which could be remedied by their removal.
- 9.11 We have already described the history of PNGL's regulation. However, in order to assist in understanding this section, the key events are these. In September 1996 there was an agreement between the Department of Economic Development and British Gas to enable the creation of a gas distribution network in Northern Ireland. British Gas's subsidiary, PNGL, was given a licence to convey gas (at transmission and distribution levels) and to supply gas in the areas of the licence. This was set up on the basis of a 20-year recovery period. A framework was also established for the regulation of PNGL. The key features of the regulation devised in 1996 were that revenue recovery was profiled over the 20-year period to reflect the time needed to build volumes to a sustainable level, with a fixed 8.5 per cent real rate of return for that period. Price control reviews would reset price caps based on revised cost and volume forecasts. PNGL was given output targets (such as number of properties passed) reflecting a mandatory development plan. PNGL was allowed to retain any difference between allowances and actual expenditures; in effect it was therefore allowed to retain 100 per cent of outperformance as an incentive to pursue efficiencies.
- 9.12 Two determinations or redeterminations were made under the 1996 regime. PC01 in 1999 set the first allowances. In 2002, PC02 made further changes, most notably for present purposes allowing an increase in conveyance charges. However, discussions subsequently took place over the original 1996 approach and whether it was possible or appropriate to seek to recover all investment costs within a 20-year period given the lower than anticipated levels of customer uptake and demand for gas that were realized, and the implications of increasing prices substantially to achieve this. A major change to the original regime was made in 2007 as part of the PC03 determination. This was an important reform of the regime, the most significant changes being an extension of the cost recovery period from 20 years to 50 years; the introduction of a price control mechanism based explicitly on a regulated asset value; the determination of an OAV of £312.8 million (which included not just actual expenditure on investment, but also revenues that had been earned to repay actual expenditures but not yet recovered from customers up to that point, and also unrecovered outperformance), and a reduction in the rate of return from 8.5 to 7.5 per cent. That regime has been in force unchanged until now.
- 9.13 In making our findings on the public interest, we have taken account of all the duties and obligations to which UR is subject and of the priorities accorded those different duties and obligations. During the course of our investigation, and in particular after publication of our provisional determination, UR has provided us with its analysis of the relationship between the different duties and obligations to which it is subject.

This has furnished us with a clear view of UR's understanding of its legal responsibilities. While ultimately we disagree with UR about the extent to which the public interest is served by the present price controls, we do not think that difference arises because of a different view of the regulatory framework. We think instead that the difference follows from a different view of the ways in which the public interest (including consumer interests taken as a whole) is best served in the particular context of PNGL's business.

Discussion of issues

Opex and capex allowances and other non-disputed matters

- 9.14 UR told us⁵ that having examined PNGL's business plan it had proposed an allowance for opex and capex in 2012 and 2013 using a standard RPI-X framework. PNGL's submission on capex was reviewed by UR with the help of engineering consultants. An ongoing efficiency factor of 1 per cent was also applied (see paragraph 2.62). UR told us that PNGL had accepted its determination on these allowances, and PNGL confirmed its agreement before us.
- 9.15 We have reviewed the proposed allowances but not conducted a detailed assessment of them, in part because there was no evidence proffered that the allowances were inappropriate and, in any event, there was no substantive disagreement between the parties. Indeed one notable feature of this inquiry is that opex and capex allowances, which typically are a major bone of contention in a regulatory inquiry (and so are the subject of considerable review and analysis by the CC and are a major focus in investigations of this type), in this case proved uncontentious. Our review showed no reason to believe that the proposed allowances were out of line with what was required for PNGL properly to undertake its activities and invest in the distribution network.
- 9.16 We accept that the existing capex and opex allowances are no longer appropriate going forward. Therefore we consider that the existing opex and capex allowances operate or may be expected to operate against the public interest and that they need to be revised. The revisions proposed by UR and accepted by PNGL are, after scrutiny, in our view appropriate.
- 9.17 UR has also concluded that change is needed on a variety of further issues which have not been disputed by PNGL, such as amendments to PNGL's connection incentives. We reviewed the changes proposed and did not identify any issues of concern. Other differences compared with PC03 are:
- the targets for connections, number of properties passed and km of mains laid (ie parts of the outputs of PNGL);
 - the assumptions on the volume of gas that will be consumed (for the period 2012 to 2046); and
 - the calculations for the 2012 opening TRV (before UR's adjustment) including the application of the retrospective adjustment mechanism.
- 9.18 We also accept that the current arrangements on these issues need to be revised to suit current circumstances and so conclude that the current arrangements are or may be expected to operate against the public interest and should be revised as proposed

⁵ As noted in paragraph 2.62.

in PNGL12. Some concerns, addressed in paragraphs 4.118 to 4.29, were raised by CCNI. However, we agree with UR's determination on these matters.

Rate of return

- 9.19 UR did not propose to revise PNGL's rate of return in its PC2012 determination. However, during the course of our investigation it suggested that if we did not accept UR's other proposals, we should consider whether the rate of return should be reduced.⁶
- 9.20 Under the 1996 licence PNGL was allowed to earn a fixed, real, pre-tax rate of return of 8.5 per cent for the period 1996 to 2016. Subsequently, as part of the 2007 determination,⁷ that rate was reduced by 1 per cent so that PNGL was allowed a fixed, real, pre-tax rate of return of 7.5 per cent for the period 2006 to 2016.
- 9.21 We have carefully considered submissions from UR and from third parties which express concern that the 7.5 per cent rate of return fixed for 2006 to 2016 exceeds the forward-looking WACC⁸ for PNGL in 2012 and 2013. As set out in paragraphs 7.83 to 7.90, we agree that the forward-looking WACC in 2012/13, excluding compensation for project-specific risks, is likely to be lower than the allowed rate of return of 7.5 per cent. In order to assess whether a rate of 7.5 per cent operates or may be expected to operate against the public interest, we have sought to establish whether it is appropriate to allow a premium above the forward-looking WACC to compensate for project-specific risks. While PNGL took on a high degree of risk in 1996, developments since 1996, and in particular the regulatory changes of 2007, have mitigated that risk in some degree.
- 9.22 We have reviewed, in so far as it is possible, the manner in which the rates of return were set in the original licence in 1996, and in the 2007 determination (see Section 7). However, this exercise has proved difficult due to the lack of contemporaneous documentation setting out the rationale or methodology for setting the rates of return in 1996 and 2007. In particular, we saw no calculations from UR or PNGL of the forward-looking cost of capital, or quantification of the project-specific risks, faced by PNGL at either time. Rather, the rates appear to have been reached by negotiation.
- 9.23 Because of that lack of documentation, our approach has necessarily involved a degree of ex-post rationalization, based partly on our assessment of what PNGL and UR told us and partly on our views of the risks confronting PNGL at the time. We note that the rate of return set in 2007 was linked to the rate of return set in 1996 (in that it retained the original 20-year time frame as this rate was projected to apply until 2016). For this reason, we consider the rationale for the 1996 rate of return first, before turning to that set in 2007. The following paragraphs summarize the assessment set out in Section 7.

⁶ In its Introduction to the Reference, UR stated: 'we welcome the scrutiny that we anticipate the Commission will now wish to give ... particularly to the proposed cost of capital allowance'—see UR [initial submission](#), paragraph 1.25, p7. In its [response to the provisional determination](#), UR said (paragraphs 6.5–6.7), 'If, for some reason, the Commission is unwilling to change its views, it must look much more broadly at its price control proposals with a view to ensuring that customers are not being asked to pay a penny more than they should and that its proposals do not operate against the public interest. We would ask, in particular, that the Commission looks at: ... whether it is appropriate to roll up the unpaid out-performance at PNGL's full cost of capital; its decision to reward new investment in 2012 and 2013 at a premium rate of return ... Each of these has the potential to give a small amount of relief from excess prices.' The first of these points is also addressed in paragraph 9.78.

⁷ UR, [Phoenix Natural Gas Limited Price Control Review 2012–2013: Final Decisions](#), January 2012, UR 13.1, paragraph 3.32.

⁸ The forward-looking WACC (weighted average cost of capital) reflects a blend of the company's expected cost of debt equity at the expected gearing ratio. The expected cost of equity, calculated according to the capital asset pricing model (CAPM), rewards investors for bearing systematic risks. It does not reward investors for project-specific risks.

- 9.24 We carefully considered the risks faced by PNGL; the different types of risk it faced at different times are set out and considered in Section 7. PNGL faced a high degree of uncertainty when making its original investment: there was uncertainty about future volumes of gas to be conveyed and about the capital and operating expenditure necessary to develop the network, as well as uncertainty about the future regulatory regime and political environment. These various uncertainties meant that PNGL faced more than a non-trivial risk that it would not recover all of its investment, including accumulated operating and capital expenditure. In order to make the investment in 1996, PNGL would have required compensation for these project-specific risks.
- 9.25 In addition to project-specific risks, we also consider that PNGL was likely to have faced a high WACC in its initial years, most notably due to high volume risk. In particular, we thought that new connections could be sensitive to economic conditions. We consider that as the network matured over time, the forward-looking WACC was likely to reduce.
- 9.26 In this light, we consider that there was real justification for setting a 20-year fixed rate of return at the outset of the investment programme in 1996, because it gave PNGL a commitment that investment would receive a rate of return above the WACC for a fixed period of time in return for assuming the high upfront risks associated with the project. We recognize that we are unable, in 2012, to calibrate the numbers with any precision, given the lack of contemporaneous documentation quantifying the risks faced at the time.
- 9.27 We considered PNGL's argument that the 8.5 per cent rate of return represented an average rate of return for a 20-year period in which risk was higher at the start of the period than at the end but in which compensation for risk was spread evenly. PNGL told us that the rate was just such an average and that it would be opportunistic to adjust returns based on actual risk.⁹ UR told us that whilst it could see that this kind of declining risk profile applied to certain categories of risk such as that associated with capital expenditure, the fundamental risk facing PNGL was that of under-recovery and this risk increased as the end of the recovery period, 2016, drew nearer. Our appraisal of the facts suggests to us that the uncertainty facing PNGL, and hence the risks, were likely to be higher at the time of initial investment and were likely to moderate over time as events unfolded and uncertainty was resolved. Whilst we accept that, as 2016 drew closer, PNGL would have more information on which to judge the extent to which it might recover its investments, we viewed this as a resolution of uncertainty rather than indicative of higher risk. While this matter is not free from doubt, it seems most likely to us that the rate set in 1996 represented an average and that PNGL was under-compensated for its risks in the early years of network development.
- 9.28 We next consider the 7.5 per cent rate of return set as part of the PC03 determination in 2007 and which was fixed for the period 2006 to 2016. This represented a 1 per cent reduction from the 8.5 per cent agreed in 1996.
- 9.29 We consider that the 2007 determination represented an important reform of the original regime which was beneficial to consumers and to PNGL, and which resolved many problems associated with the earlier regime. Most notably it increased the period over which PNGL could recover its investments, so improving PNGL's incentives to continue to invest in the network¹⁰ and thus reducing the risk of large price

⁹ See paragraph 7.6.

¹⁰ This extension of the period reduced the risk that PNGL would not recover its investment within the licence period (which would have become increasingly unlikely as the number of years left in the licence period reduced), and so improved PNGL's incentives to continue investing in the network.

increases for consumers (which would have been likely as, absent the 2007 determination, PNGL would have needed to increase substantially the prices it charged consumers so as to cover the cost of its investments by 2016—see paragraphs 2.43 and 2.44). In this context, we have considered whether there was any justification for continuing to recompense PNGL for project-specific risk that it assumed in 1996.

- 9.30 We think that there was real uncertainty over PNGL's ability to recover its investments leading up to the 2007 determination and that the PC03 framework removed much of this uncertainty by introducing a RAB and extending the licence recovery period. However, we note that PC03 did not remove all uncertainty; there were a number of unresolved areas, such as the connections revenue driver which was not resolved until later, and the extension of the recovery period meant that revenues were profiled many years into the future.¹¹
- 9.31 We viewed the 2007 determination as a change to the original 20-year project rather than terminating (and fully rewarding) the initial project and starting a new investment project in its own right. While the determination and publicity at the time noted the beneficial effect of these changes (particularly in extending the licence period), they did not portray this as a fundamental new start to the regime, nor was there consultation on the proposed changes on this basis, and the 2007 determination carried forward capitalized historic outperformance and continued to recognize the principle of a 20-year agreed rate of return. We considered that there could be justification for retaining elements of the original agreement, including the commitment to reward PNGL with a fixed rate of return for a period of 20 years. In our view, the project-specific risks that PNGL assumed in 1996, and the distinct possibility that PNGL was under-rewarded for risks between 1996 and 2007, remain relevant considerations. At the least, after 2006 it ceased to receive the same level of reward for assuming project risk which in 1996 it had expected to receive for a 20-year period.
- 9.32 While we consider that PC03 represented a change to the original project which did remove some uncertainty, and which is reflected in the reduction of the rate of return at that time, in the context of all the changes that occurred at that time (and because we consider this to be a continuation of the existing project—see paragraph 9.31) we think that there was adequate justification for not departing from retaining a fixed rate of return, incorporating a return for project risk, for the remainder of the original 20-year period.
- 9.33 Moreover, whilst in 2007 PNGL was better established, it was a still developing network utility which remained immature compared with Great Britain utilities. As a result, we consider that the forward-looking WACC was likely to be relatively high in comparison with Great Britain utilities. We think that the considerations noted above support the PC03 decision in 2007 to fix a 7.5 per cent rate of return until 2016.
- 9.34 We now consider whether, in view of the above, the maintenance of a fixed rate of return of 7.5 per cent in 2012/13 operates or may be expected to operate against the public interest. We observe that the forward-looking WACC for PNGL in 2012 and 2013 is likely to be lower than 7.5 per cent, because PNGL is increasingly mature and the regulatory framework has become more standardized. On the other hand, we note that revenue continues to be deferred into the future, that elements of the regulatory regime are still developing and that there is a need to ensure continued investment for the future development of the network. We have seen nothing to indicate that circumstances have changed such that the commitment made in 2007 to fix the

¹¹ Hence recovery of costs would be dependent on levels of demand far in the future which are inevitably hard to forecast and inherently subject to risk (although mitigated by the process of periodic price redeterminations).

rate of return until 2016 should be reversed. However, we recognize that there is a judgement to be made about the length of time over which it continues to be appropriate to maintain a fixed rate of return that may be above the forward-looking WACC, in a context where important revisions have been made to the original approach but where continued expansion still needs to be ensured. This judgement (to which UR will return in 2014) must of course be made against the question whether maintenance of the fixed rate operates or may be expected to operate against the public interest.

- 9.35 The conclusion that we have reached is that we cannot say that a fixed, real, rate of return of 7.5 per cent is against the public interest. It remains appropriate that a project risk premium should be allowed to supplement the WACC in 2012/13. We note that matters will be considered again in the course of future price reviews and necessarily in 2016, when the period of application of the 7.5 per cent rate comes to an end. We should add that had we come to a different prima facie conclusion for the 2012/13 price control, we would have had to consider whether, notwithstanding, the rate of 7.5 per cent should continue to be allowed. There is a risk, because of expectations that may have developed that the rate would continue until 2016, that the consequences of not maintaining the current rate would be to reduce the willingness of investors to invest in future development of the gas network (and possibly other regulated sectors in Northern Ireland) and could increase the cost of capital applying to them if they have as a result less certainty over the return they could expect to achieve.
- 9.36 We consider that in order to determine that PNGL's current rate of return operates or may be expected to operate against the public interest, we would have to be satisfied that it was not in the public interest to embody that rate in PNGL's price control, taking into account the project-specific risks that it assumed in its greenfield development of the gas distribution network, as well as the other factors mentioned above and the implications for customer charges. We are not so satisfied. There is insufficient evidence to lead us to that conclusion, and there are good reasons to think that the maintenance of a project risk premium is consistent with both the future and past project risks faced by PNGL. We do not therefore consider that we should disturb the position reached in PC03.
- 9.37 We therefore conclude, taking account of the balance of factors relevant to the public interest, that departing from the fixed rate of return of 7.5 per cent in the forthcoming charge control period is not required because that rate does not operate or may be expected to operate against the public interest.

Elements of the TRV

- 9.38 We now consider whether inclusion of components within the TRV (at their existing size) operates or may be expected to operate against the public interest.
- 9.39 As noted in paragraph 9.3, UR considers that 'the payment by gas consumers in Northern Ireland of higher prices for the conveyance of gas by PNGL than are necessary or appropriate' is against the public interest. It has proposed a remedial adjustment to the TRV by which values for historic outperformance and deferred capex would be removed. UR invited us, if we did not agree to removing historic outperformance and deferred capex, to consider alternative remedies. In summary, UR argued that the 2012 TRV adjustments were part of its process of moving to a RAB-based regulatory system, that PNGL had already been rewarded for historic outperformance in a way consistent with normal practice under a RAB-based system, and that not to make an adjustment would over-reward PNGL and be contrary to the interests of customers. For example, it said:

... leaving the value of outperformance in the TRV to be depreciated and earn a rate of return up to 2046 over-compensates PNGL, and does so at the expense of consumers. Even if the sums in question represented genuine efficiencies, allowing PNGL to earn a regulated return for 40 years would provide a degree of compensation to consumers far beyond anything that could be obtained in a competitive market.

- 9.40 UR told us that the point of revising the TRV was not to deliver a benefit to customers for its own sake, but to strike the balance required by its duties.
- 9.41 We accept that, as a simple matter of the application of the price control conditions in the licence, a reduction in the TRV would result in lower prices being charged to customers. The question is whether it is right to adopt this course, and this requires us to consider whether the current price controls operate or may be expected to operate against the public interest.
- 9.42 The revisions proposed to the TRV by UR highlight most sharply the potential for conflict between three considerations that arise from the unusual context of our determination and which are relevant to a determination of whether the existing TRV operates or may be expected to operate against the public interest. These are the legacy issues from the early period in which the gas distribution network was first developed, the still developing network, and the progress that UR and PNGL are making towards conventional RAB-based regulation. The regulatory regime has itself—and this is hardly surprising—developed considerably since 1996 (see paragraphs 2.38 to 2.60). The risks and rewards faced by PNGL itself have also changed. Initially PNGL was a start-up company developing a new service under considerable uncertainty on a greenfield basis. It was offered a 20-year licence to undertake the development of the network and recover its costs at a fixed rate of return. The regulatory regime changed substantially in 2006/07 because of shortcomings in this approach, primarily the challenge of recovering costs within 20 years when customer numbers had not realized the initial aspirations, which would necessitate very large price increases. At that time of under-recovery while the business was being built up, outperformance was capitalized into the TRV.

Outperformance

- 9.43 Under the 1996 licence and in the regulatory framework applied under PC01 and PC02, until 2006 PNGL was entitled to receive and retain 100 per cent of its outperformance. In other words, where PNGL incurred less opex or capex than anticipated, the benefit of the saving fell entirely to PNGL (and it bore the cost of underperformance if it incurred more opex and capex than anticipated). We reiterate (see paragraph 5.2) that the purpose of allowing companies to achieve a return on outperformance is to incentivize them to find cost savings in operating and capital expenditure (with a share of the benefits of these lower costs ultimately being passed to customers either through a sharing of outperformance or through ‘ratcheting’, facilitating the setting of more challenging price controls in subsequent periods). Because of the back-end loading of revenues when it was anticipated that greater gas volumes would apply in later years, and because PNGL under-recovered against the revenues it was entitled to charge under the price cap (see paragraph 2.52), PNGL was unable to recover all the outperformance at the time it accrued.
- 9.44 The retention by PNGL of outperformance in its entirety contrasts with UR’s current view that outperformance should be shared between PNGL and its customers. A system of rules to ensure that there was such a sharing of capex outperformance was introduced in the PC03 determination in 2007, but those rules applied only to

future outperformance.¹² Under the PC03 determination, outperformance arising before 2007 but for which PNGL had been unable to take the benefit as it arose was capitalized into the TRV. In consequence, under the current licence PNGL recovers pre-2007 outperformance including capitalized financing from current and future customers. UR now wishes to change that.

- 9.45 We have examined elements of the history of the outperformance capitalized into the TRV in 2006 for two reasons: first, because UR expressed concern that such outperformance was not necessarily the consequence of efficiency; and secondly, because the reasons for the capitalization are important in understanding the context in which PNGL has been regulated and are relevant to our determination.
- 9.46 In paragraphs 5.73 to 5.123, we reviewed whether outperformance represented genuine efficiencies. We acknowledge that it is possible that outperformance can be recorded for reasons other than genuine efficiency, for example because allowances were insufficiently challenging or because a company does not achieve the standards of quality and output expected of it. There is a risk that some regulated companies may try to 'game' the system in their submissions to the regulator on the levels of costs and efficiency gains that can reasonably be expected or by sacrificing quality. However, we have seen no clear evidence that PNGL's outperformance has been inefficient for these reasons. This in part seems to be because no systematic assessment was done of outperformance after it had been accrued, and because the information available to UR in the past did not lead it to conclude that such a review was needed.
- 9.47 UR did particularly refer to the accumulation of outperformance between 1996 and 1999. The benchmark costs set in the PC01 decision in 1999 were, according to PNGL, based on tender rates. Given that there was no established natural gas industry in Northern Ireland at that time, we cannot be certain that the rates determined by competitive tender were at fully efficient levels. Further, given the inevitable uncertainty around a greenfield development, and the substantial contract revisions which occurred between PNGL and McNicholas (its contractor) between 1996 and 1999 (including a profit-sharing arrangement by which both parties would benefit from outperformance), there is some doubt whether those tender rates represent a meaningful benchmark of efficient prices and thus whether outperformance really is outperformance.¹³ It is also notable that PNGL managed comfortably to surpass the targets set for it. However, while such arrangements may justifiably lead to concerns that outperformance may have reflected shortcomings in the tender process rather than genuine efficiency, these concerns do not by themselves establish that this was the case. We have not been able to identify information that would enable us to assess whether or to what extent the pricing benchmarks used from 1996 to 1999 were inappropriate, such as, for example, an assessment of rates in Northern Ireland compared with elsewhere in Great Britain.¹⁴ This is because no detailed assessment was undertaken at the time. In the absence of such information, we are unable to conclude that the outperformance was not the consequence of efficiency. While it is possible to level criticism at the tender process, its weaknesses are not so large, nor the consequences of those weaknesses so inevitable, as to lead us to conclude that outperformance should be discounted.

¹² UR told us that this interpretation was incorrect, as it had intended that the sharing of outperformance would refer to historic as well as future outperformance. We do not agree, for the reasons set out in paragraphs 5.155–5.159.

¹³ See paragraph 5.95.

¹⁴ Such a comparison would not necessarily be informative anyway, if the circumstances differed between Northern Ireland and Great Britain, for example because a natural gas distribution industry already existed in Great Britain.

- 9.48 We are in no doubt that in 1999, when UR set the first allowances, it must have appreciated the consequences of allowing PNGL to recover unit cost outperformance from the prior years. While it is perhaps surprising that UR did not explain its treatment of outperformance in the PC01 decision, it would have been aware that there was outperformance albeit its apparent conclusion that there was no need separately to identify outperformance in the licence formulae.
- 9.49 We note that in the regulatory settlements to date, UR has chosen not to undertake efficiency assessments of outperformance between 1996 and 2006, although it had some relevant evidence at its disposal including consultants' reports (covering PNGL's investments and costs, which could have alerted it to possible issues developing). This indicates that it was content at the time of those determinations that the treatment of outperformance was as intended.
- 9.50 Our review of the regulatory history of outperformance has not led us to conclude that outperformance has not been genuinely earned. This is a relevant factor to include in the balance of the consideration of the public interest. However, that does not mean that revisions cannot be made in the public interest where appropriate, which we assess in paragraphs 9.94 to 9.109.
- 9.51 We considered whether, despite the weaknesses in the available evidence, it would still be appropriate to make an adjustment to historic outperformance because of the possibility that some was inefficient (and thus, even without consideration of the wider balance of interests, could be said to operate against the public interest). We have decided that no such adjustment should be made because there is no basis for identifying whether any significant element of historic outperformance was inefficient, or what proportion this would be. We also note that the 1996 licence made no distinction between legitimate and inefficient outperformance, and UR did not make any such adjustments to outperformance when it arose or at subsequent reviews.
- 9.52 In addition, we have given weight to the problems with unheralded ex post adjustments to accrued outperformance after the outperformance has arisen. It is preferable that adjustments are made to the way in which outperformance occurring in the future is treated. In this case, historic outperformance has been set as part of the TRV and normal regulatory practice is that there is some degree of commitment to maintaining the TRV. Adjustments to past outperformance may have an effect on the perception of regulatory stability, as described in Section 8, which could in future increase the costs of funding regulated industries or deter investment.
- 9.53 The treatment of outperformance in successive price controls has been to allow PNGL to recover and retain outperformance over the long term. We believe that this reflects a recognition by the regulator that, prior to the current price control review (and in addition to the familiar purpose of incentivizing PNGL to pursue efficiencies and cost reductions in its operations), development of the network was best served by allowing PNGL to obtain a benefit from outperformance (see paragraph 9.54). This is so even if that benefit could not be realized in the period in which it arose because of revenue profiling (ie that allowed revenues are only recovered from customers at a later date when the number of customers has grown, so as not to burden current customers with very high prices). This regulatory approach has no doubt fostered an expectation in PNGL that it will be able to recover historic outperformance.¹⁵

¹⁵UR said that in this case it had already been set out that historic outperformance would be treated in line with practice elsewhere. However, as noted in the footnote to paragraph 9.44, we do not accept that this had been signalled.

- 9.54 While neither consideration—the regulatory approach to date or PNL’s expectation—dictates the approach that we must now adopt, both are relevant considerations in determining whether maintaining the current TRV operates or may be expected to operate against the public interest. It is not simply that successive settlements have taken a particular approach to outperformance and that some form of expectation may understandably have developed. More important are the underlying rationales for that approach, which we believe to be: first, to encourage efficiency and reduce long-run costs; second, to serve as a heightened incentive mechanism (which increases the potential rewards available) and so indirectly increases the degree to which the business is resilient to the effects of risk and thereby increased its initial willingness to incur risk; and third, to reflect the need for flexibility in the regulation of a start-up business of gas distribution where the requirements of the regulatory environment will almost inevitably develop. Where, as here, initial regulatory arrangements have to be developed, it may also be necessary to recognize that considerations germane to earlier regulation may still be relevant.
- 9.55 We considered whether different issues were applicable to WCA outperformance given that different arrangements applied to the way this outperformance was incorporated into the TRV (see paragraphs 5.160 to 5.172). However, we saw no reason why the same principles in relation to the achievement of outperformance should not also be applied to working capital.

Deferred capex

- 9.56 We now address two categories of deferred capex: deferred capex that is included in the TRV under the general classification of outperformance (and which is discussed in more detail in Section 5), and separately a set of specific capex projects that were deferred from 1999/2000 (and which are discussed in detail in Section 6).
- 9.57 In relation to the first category, these sums largely arise from the capitalized financing that has arisen on investments that were deferred in the past¹⁶—see paragraphs 5.15 to 5.120 and Tables 5.1 and 5.2. Capex deferrals can represent a rational and efficient action by a company, ensuring that the investment that occurs is best suited to the changing circumstances and strategies and is not built at an unsuitable time purely because the company is incentivized to make the investment regardless so that it can then charge customers in order to recover the costs of the assets. Such deferrals should then inform the determination of capex allowances in future periods (ie future determinations would be modified as in the ratcheting mechanism). On the other hand, because PNL was entitled under the rules then applying to 100 per cent outperformance including on deferred capex, there was the possibility that it could be rewarded even though it had simply not undertaken necessary investment.
- 9.58 The information we have available is not sufficient to establish whether or not these deferrals were efficient (see paragraphs 5.73 to 5.123). In other words, we cannot tell whether they arose as a result of genuine cost-reducing efficiencies, or benefited customers by better timing or redeployment of capex (such as running pipes to areas with the highest likelihood of demand rather than sticking to a fixed roll-out plan), all of which are positive, or whether they simply allowed PNL to gain a financial benefit from delaying investment so that it could earn a return before an investment was actually made. UR did not undertake an appraisal of whether deferrals were efficient, other than for certain specific capex deferrals that UR explicitly considered efficient (see paragraph 5.98c), and where UR granted PNL the original allowances including capitalized financing benefits as a result of its efficiency assessment without

¹⁶ Whereas the original allowances have largely been spent, albeit later than envisaged in UR’s determinations.

mandating any sharing with customers. However, we understand that all other categories of capex (apart from the 1999/2000 capex deferrals) were not subject to an assessment.

- 9.59 We considered (see Section 5) whether there were any technical errors¹⁷ in the way deferred capex had been treated, but we did not find that to be the case.
- 9.60 We considered whether there were other reasons to exclude deferred capex from the TRV, because its inclusion operates or may be expected to operate against the public interest because it did not deliver benefits to customers. However, as noted above, it has not been demonstrated that capex deferrals are not efficient. We also note that the regulatory regime between 1996 and 2006 allowed PNGL to benefit from capex deferrals, and this contributed to PNGL's expectations of how it would be rewarded and helped shape its investment strategy. This is a relevant (but not overriding) consideration. However, we also think the same point applies as in paragraph 9.54, that these rules have and continue to serve as a heightened incentive mechanism (offering increased potential rewards), which indirectly affects the degree to which the business is resilient to risk and increased its initial willingness to incur risk at a given rate of return. PNGL's position is still less stable than that of a mature utility whose main costs are the replacement of existing infrastructure save for limited and discrete expansion, and so is subject to additional risk. For these reasons, we do not consider that the inclusion of historic deferred capex (and the financing returns on these sums) in the TRV operates or may be expected to operate against the public interest. Apart from growing its customer base, PNGL is still rolling out its network (although near the end of that process in the current Licensed Area).¹⁸ The principle objective (according to Article 14 of the Energy Order—see Appendix B) is to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland. The investment necessary to achieve this requires appropriate incentives without the deterrent effect that might arise if the regulatory environment was not seen to be stable (see paragraphs 9.110 to 9.114).

1999/2000 capex deferrals

- 9.61 We now turn to the 1999/2000 capex deferrals, where, in contrast to the general category of capex deferrals, we can identify specific projects and the duration of deferrals that apply. The following paragraphs summarize our assessment set out in Section 6. In its PC03 charge control decision, UR indicated that it would reassess the treatment of the 1999/2000 capex deferrals. We distinguish between those projects which were deferred but had been completed by the end of PC03, and those projects which remained uncompleted.
- 9.62 These projects largely referred to capacity reinforcements that had fallen into abeyance (if not falling away permanently) when PNGL changed its strategy around 1999/2000. A distinguishing feature is the extent of time for which these projects have been deferred. This raises the question of when deferral of capex can be regarded as constituting an absence of investment. It would appear counterintuitive to offer a regulated company a return on an allowance to undertake a project that it has not undertaken for an extended period and/or that it is not going to undertake. PNGL told us that these projects remained in its intentions and they would be required at some time. However, it appears to us now, given the revisions of the

¹⁷ By technical errors, we mean, for example, the input of incorrect data or an erroneous mathematical calculation, which are clearly wrong. It does not refer to differences of opinion on judgement and discretion.

¹⁸ UR stated that PNGL's network would be completed by the end of 2014 and then, as it would have a modern network in place, rates of capex would be relatively low.

investment policy in 1999, that the need for these projects in the foreseeable future has dropped away. As a general proposition, it seems that there must be some threshold where, rather than considering deferrals as appropriate, one should consider that retention of seriously delayed, or irrelevant or superseded, projects in the portfolio of intended investments is no longer appropriate and they should be removed and only reinstated when they are immediately relevant to the current strategy. Put another way, deferral of capex is appropriate where customers may benefit from that, but not to the point where customers have to pay for the company not to undertake a project it did not intend to undertake (or not to undertake for a long period of time). Where that threshold lies can probably not be determined on a generic basis but only by reference to the specific circumstances of each situation. We consider that, in this case, the projects which have not been completed can now be regarded in that light given that on any view a threshold of more than 11 to 12 years is too great.

- 9.63 As noted in paragraph 6.22a, the relevant question for charges to customers is to what extent PNGL should be allowed to retain the capitalized financing on the sums that have been discussed above. We consider that the appropriate time to draw a distinction is when it could be recognized that these projects were no longer relevant to the immediate investment and operational strategy. We recognize that this was not necessarily in 1999/2000. It is possible that PNGL was unsure when these capacity enhancements would be required, for example if this depended on the unknown future demand for gas arising from its new network developments. It may well have taken some time for this to become apparent, if it was assessed in this way. We are not aware of evidence that could help us take a view on this, although we note that in the PC03 determination, UR signalled that it would look again at these projects, suggesting that there was some awareness of an associated issue.
- 9.64 Therefore, we consider that by 2007 it was likely to be apparent that these projects may not be required in the near future. However, we recognize that there is considerable uncertainty around the facts and what was understood at each point in time.
- 9.65 We also looked at the PC03 determination. We note that this established an amended regulatory framework which defined a set of rules for the treatment of deferred capex that might arise in the future. These rules have been, we understand, accepted by both UR and PNGL as fair and appropriate. UR, in PC03, changed its approach to the treatment of deferred capex so that any future capex deferrals that happened from 2007 onwards would be removed from the TRV by retrospectively reducing the capex allowances in PC03, including capitalized financing and in some cases including the management fee.¹⁹
- 9.66 On balance, taking into account our view that the 1999/2000 capex deferrals that were not completed by the end of PC03 were unlikely to be needed in the foreseeable future, and have already been deferred for a long period of time, we think that it is appropriate to apply the new approach introduced in PC03 in relation to forward-looking capex deferrals.
- 9.67 The PC03 regulatory approach generally foresees that PNGL would no longer benefit from capex deferrals (ie PNGL would not retain the allowances and associated capitalized financing for capex deferrals and in some cases an adjustment would also be made for the management fee).

¹⁹ See paragraph 6.10 **Error! Reference source not found.** See also UR [PNGL12 determination](#), Annex 5.

- 9.68 We therefore think that the 1999/2000 capex deferrals that have not been completed by the end of PC03 should be removed from the 2012 TRV, including the capitalized financing benefit that accrued to PNGL since 2007. Their inclusion operates or may be expected to operate against the public interest because they cannot be said to deliver any benefit to consumers, whether directly or because of their incentive effects on PNGL, yet their inclusion will have an impact on the prices currently paid by consumers. However, the regulatory framework established in PC03 does not support an adjustment for capitalized financing that accrued before 2007, because the PC03 regulatory framework provided a forward-looking treatment for deferred capex from 2007 onwards and the 2007 determination included the capitalized financing benefit that had accrued on the 1999/2000 deferrals (and all other capex deferrals) until 2006 in the 2006 TRV.
- 9.69 We also considered whether there should be any adjustment for those projects deferred from 1999/2000 but which were completed by the end of PC03. In these cases, it is clear that these projects have remained relevant as they have gone ahead. The question is therefore how much capitalized funding should be realized on these. There is no clear a priori case to say that these projects are different from the bulk of deferred capex (other than the uncompleted projects) which we have allowed.
- 9.70 We also considered how these would be treated under the PC03 rules.
- 9.71 In the PC03 determination, UR established a clear framework for the treatment of deferred capex that was projected to be completed in PC03. The PC03 determination foresaw that some of the 1999/2000 capex deferrals (and, for example, deferrals for infill and feeder capex from previous charge controls) would be constructed during PC03, and as a result UR reduced PNGL's capex forecasts by the deferred capex projects that were planned for PC03 (because these were already funded in 1999/2000), without signalling further adjustments once the projects were built. We therefore think that it is appropriate to make no further adjustments for those 1999/2000 capex deferrals that were completed by the end of PC03, as the related funds have now been spent and as the PC03 determination did not foresee further adjustments once these funds had been spent.²⁰
- 9.72 Therefore, in summary, the application of the PC03 rules indicates outcomes consistent with our judgement that the inclusion of the 1999/2000 deferred capex projects that were not completed by the end of PC03 (and the associated capitalized financing benefits arising since 2007) are inappropriate because they operate or may be expected to operate against the public interest. Consequently we conclude:
- (a) For those 1999/2000 capex deferrals that were completed in PC03, no further adjustments are made.
 - (b) For those 1999/2000 capex deferrals that were not completed in PC03, an adjustment equivalent to the retrospective adjustment mechanism that applies in PC03 should be made, ie the 1999/2000 capex deferrals that were not completed in PC03 are removed from the TRV including the capitalized financing benefit that accrued to PNGL since 2007, but that no further adjustments should be made.
- 9.73 Applying the 2007 cut-off does not take account of the specific circumstances of each individual project, including, for example, whether PNGL has self-financed other projects instead (nor does it consider deferrals that do not fall in the 1999/2000 capex

²⁰ See, for example, Appendix C, paragraphs 157–159.

deferral category). However, we consider that it is a reasonable judgement given the limits on what can now be done to assess the efficiency of deferrals.

- 9.74 We also found (see paragraphs 6.64 to 6.70) that it would be appropriate to make an adjustment of 5 per cent for the management fee saved by PNGL by not completing these projects, as we think that the management fee was part of the 1999/2000 capex deferral projects and as there is a risk of funding PNGL twice for the management fee if PNGL applies for funding of these projects in the future.
- 9.75 Having assessed that inclusion of the original unspent allowances for 1999/2000 capex deferrals (including the management fee) and capitalized financing in the TRV is against the public interest, we now address the question of the appropriate remedial mechanism to deal with this. UR's preferred approach for dealing with the initial allowances was to align the treatment of these amounts with the approach that it had set out in 2007 for deferred capex arising in PC03, ie the amounts should be removed from the TRV. PNGL did not agree with this and argued that the unspent allowances should be kept in the TRV but future capex allowances should be reduced accordingly.²¹
- 9.76 We think that the question of whether the adjustment for deferred capex is made by netting it off future capex allowances or by reducing the TRV is largely irrelevant, because the adjustment could be calculated for either option so that it would have exactly the same impact on the price cap for PNGL (ie the financial effect of the two different treatments could, in principle, be the same). We do not think that there are strong reasons to prefer one treatment over the other, but on balance we agree with UR that making a TRV adjustment is simpler as it does not require additional adjustments to forecast capex allowances. We therefore made the adjustment for the 1999/2000 capex deferrals directly in the TRV.

Whether full inclusion of outperformance in the TRV is against the public interest

- 9.77 We have already considered one issue raised by UR in arguing for a change, which is that outperformance may not reflect genuine efficiency. UR also made a number of other points as to why it thought that inclusion of historic outperformance and deferred capex in the TRV was not appropriate. In particular, it said:

We think it is critical to this case that the Commission set out why it would be appropriate to reward PNGL 40 year reward for outperformance in 2007. ... It is unprecedented in UK regulation where five years is the normal period for such rewards and confounds what would be expected in a competitive market. Given that UR never intended to allow such a methodology the Commission needs to set out why such a methodology is appropriate.

- 9.78 A second key point advanced by UR is that capitalization of outperformance overcompensates PNGL. We do not agree. While earning a return on an asset for a period of, in this case, 40 years will increase PNGL's return in absolute terms, the value of the capitalized sum is equivalent in financial terms to the outperformance accrued (always provided, of course, that an appropriate capitalization rate is

²¹ In this way we understood that there was a potential for PNGL to benefit from capitalized financing.

used).²² We have set out above (see paragraphs 9.19 to 9.37) why we consider that the rate of return used is not inappropriate. We therefore do not accept that the fact that the sums under consideration here have been capitalized and a return realized over 40 years means that PNGL is being over-rewarded. UR said that it was not intended that historic outperformance was to be rewarded at this rate.²³ However, we have seen no indication in the 2007 determination that it was not intended to use the same rate of return for this purpose.

- 9.79 A third point taken by UR is that capitalization does not mimic the rewards that would be obtained in a competitive market. We understand why UR uses the idea of a competitive market to test its approach to regulation. However, we do not think it is a persuasive way of thinking about the facts of this case and in particular the question of how to reward a regulated company for the development of as significant a project as the gas distribution network. In any case, companies in competitive markets may earn a higher return on any efficient innovations until matched by rivals, and this temporary return provides an incentive for innovations in a similar way to the return that a regulated company realizes on outperformance. In this case, PNGL's outperformance was not taken at the time and was capitalized into the TRV to be repaid over 40 years, but the fact that this then means that returns are realized on it for the 40-year period is addressed in the preceding paragraph.
- 9.80 UR indicated that normally, under a RAB-based regulatory system, a company would expect to earn a return on capex outperformance for only five years. We acknowledge that such arrangements would be a typical example of a regulatory incentive system applying to an established utility. We note that following PC03, the capex outperformance arrangements for PNGL have followed this model. There are, however, pertinent differences in this case, apart from the fact that when the outperformance was earned, it was earned under a different set of rules that allowed outperformance to be recovered in full. The points that incentives were intended to reward the circumstances of the investment as set out in paragraph 9.54 apply. UR stated that this failed to address the issue that the 2007 'redesign' represented a departure from the old licence and was intended to create a new package of measures. However, as noted in paragraph 9.31, we view the 2007 determination as a development of the existing project with its 20-year perspective rather than drawing a line under it and creating a new structure. Second, while historic outperformance has been capitalized into the TRV, its constituents include opex outperformance which, even under the current rules, is realized in full as it arises.
- 9.81 UR also argued that because outperformance and deferred capex did not represent 'real' investment in assets but rather simply money that had never been spent, it could be considered differently from actual investment.²⁴ However, the reward of outperformance is an intrinsic part of incentive regulation. This is because rewards for outperformance form an incentive system that drives regulated companies to seek efficient, lower-cost means of operating. In return for profits in the form of outperformance, in the longer term customers benefit from these greater efficiencies that are reflected in more demanding targets in future price controls. UR clarified that it fully supported incentive regulation, where it was in line with Great Britain practice, but it said that the fact that no investment had been made was relevant to the views of investors on regulatory certainty (it referred to the 1997 MMC Transco report (see

²² We consider that the allowed rate of return is the appropriate interest rate to use in this context. This is because the reward of outperformance is part of the incentive regime, and to use a lower rate than the allowed rate of return would reduce the power of those incentives. This is also so that the incentive to earn outperformance is the same as the incentive to use that money to make real expenditures, ie a different interest rate on accrued outperformance would reduce the relative incentive to achieve efficiencies.

²³ See paragraph 5.41.

²⁴ See UR [response to provisional determination](#), paragraph 62.

paragraph 5.62) as an example where this difference was explicitly set out).²⁵ While there may be differences of view on what is the appropriate scale and duration of reward for this type of outperformance, we do not consider in this context that outperformance should necessarily be considered separately from 'real' investment. The same reasoning applies to deferred capex. While it is possible that outperformance and deferred capex may include some inefficient elements, we cannot conclude on the evidence available that there are such inefficiencies. We consider that because outperformance is an established part of the regulatory system that serves a useful incentive function, and because the regulatory system in this case has drawn no distinction between outperformance and actual investment costs in rewarding PNGL, this distinction does not affect our conclusion that the risks of PNGL's undertaking should be sufficiently rewarded.

- 9.82 In reaching our conclusion, we have not overlooked the fact that since 1996 the risks faced by PNGL have changed, nor that in some cases where risks have arisen it has not had to face the consequences. For example, UR chose not to penalize PNGL for volume underperformance between 1996 and 1998. Rather, actual gas volumes were used in allowing the costs it could recover. The changes under the 2007 determination also reduced risks (although, as noted in paragraph 2.45, PNGL did not agree with UR that this was regulatory rescue and maintained that it would still have been able to recover its costs within the existing licence period).
- 9.83 We considered whether this meant that the return PNGL would receive should be moderated. UR told us that the regulatory de-risking that arose in the 2007 determination and the removal of the crystallized costs of under-recovery was an optional action that deserved a corresponding reduction in the rate of return. UR said that the evidence from MARs provided the best evidence that the redesign changed risk.²⁶ However, as noted in paragraph 7.61, we were not persuaded that this evidence established whether there was a particular effect on the perception of risk. The fact that risks have changed over time is not unexpected, and is part of our consideration of the appropriate rate of return in paragraphs 9.19 to 9.37. The return for taking risks after the event cannot be moderated merely because the risks have not materialized, because that would introduce asymmetry—the investor will only face the costs if the risks occur but not the benefits if they do not. It may be that UR has very properly intervened to alleviate risks faced by PNGL, but the circumstances that led to the 2007 determination equally show that the risks PNGL faced were significant. The relevant basis is therefore the perception of risks faced when they initially assumed.
- 9.84 UR's actions to moderate the impact of adverse circumstances on PNGL require closer consideration. UR said that the 2007 redesign was a fundamental departure from the 'original contract' which altered PNGL's risk profile and reinforced its financial position, so the treatment of something (eg outperformance) that was assured under the 1996 licence was up for review. UR said that it could not see how the CC could reach an informed decision without setting out explicitly the impact of the 2007 redesign on consumers and PNGL.²⁷ However, as noted in paragraph 9.31, we did not view the 2007 determination as constituting a redesign that formed a completely new start.
- 9.85 The 2007 determination might be seen as reducing risk (in that past investment and under-recoveries were incorporated into a RAB), but the determination also meant that the rate of return was reduced at the same time. This did not mean that the regime of rewards for outperformance should necessarily also be amended. In regu-

²⁵ UR [response to further consultation](#), paragraph 1.61.

²⁶ UR [response to further consultation](#), paragraph 9.78.

²⁷ See UR [response to further consultation](#), paragraphs 1.26 & 1.27.

lating the creation of an asset like the gas distribution network, we expect there to be a degree of rebalancing of risks as matters progress, but it is wrong to try to be too precise about the matching of risks and rewards in this context.

- 9.86 UR's objection to the inclusion of outperformance in the TRV is not limited to these specific points. We have approached the broader proposition of whether network charges are appropriate from several perspectives. First, we consider whether there is evidence by an objective measure that prices are too high. Second, we consider whether there are technical or other errors in the treatment of the building blocks of the regulatory system in the existing price controls. Third, we consider, taking account of relevant considerations (including the consumer interest), whether to reduce prices by revising the TRV is required, because maintaining it operates or may be expected to operate against the public interest.

Objective measures of price levels

- 9.87 We considered whether price comparisons or a review of PNGL's profitability would provide an objective measure of PNGL's price levels.
- 9.88 The aim of a price comparison would be to establish whether prices were higher than suitable comparators after taking account of any relevant differences in circumstances. For example, we considered a comparison of gas distribution prices in Northern Ireland and Great Britain. However, making meaningful comparisons is not easy. Direct comparisons of distribution prices between Northern Ireland and, for example, Great Britain are likely to be misleading because PNGL's network is newly developed, its customers are only gradually switching to gas, the costs of its initial investments are still being repaid, and its revenues have been deferred.²⁸ In addition, the geography, density of the network and so on will vary between PNGL's Licensed Area and comparator areas. Given that there are so many differences that need to be controlled for (but where measures of these differences may be difficult or uncertain), we did not think that direct comparisons of prices would be meaningful.
- 9.89 We note that UR's Energy Retail Report 2012 shows a comparison of average annual bills for a gas customer on standard credit tariffs (distribution charges are only a part of the total customer price) for natural gas in Northern Ireland compared with an average for Great Britain.²⁹ Charges in Northern Ireland have been lower than Great Britain since April 2012 but there has been considerable volatility in relative prices over time. Compared with the most recent available prices for other countries in Europe (June–December 2011), including taxes,³⁰ UR reports that the chart shows that Northern Ireland gas prices are among the lowest in Europe. However, for the reasons given in paragraph 9.88, this does not tell us whether distribution charges are at an appropriate level.
- 9.90 We also considered whether PNGL's profitability indicates that price levels are higher than necessary adequately to reward the company for its activities. PNGL presented us with an analysis of its IRR. It said that this demonstrated that the IRR was around 8.1 per cent and therefore below its allowed rate of return when that rate of return was averaged over its life. We have not undertaken a full critical evaluation of PNGL's evidence, and the returns could vary considerably depending on what assumptions are used. Whilst there are, in principle, no conceptual and practical difficulties in assessing the ex-post profitability of PNGL, the interpretation of the

²⁸ Apart from differences in circumstances in the distribution network, there are other differences that affect the overall costs consumers pay, eg in relation to the transportation system there are further costs in piping the gas to Northern Ireland.

²⁹ See [Energy Retail Report 2012](#), Figure 37.

³⁰ See [Energy Retail Report 2012](#), Figure 38.

results in this context is unlikely to be informative as to whether current price control conditions are in the public interest. Even if high profitability were found, this would not be informative without analysing the reasons for that result, and we have already addressed how the regulatory regime impacts on PNGL. For example, the profitability of a regulated company will depend on the regime to which it is subject, particularly the allowed rate of return. In this case, there is an incentive regime and so we would expect the profitability realized by PNGL to depend heavily on whether it had or had not managed to beat its performance targets with respect to outperformance. As it has outperformed, it follows that it would then be likely to earn more than the ex-ante allowed rate of return. Therefore we did not think that a profitability analysis would tell us anything which a direct examination of the regulatory regime, including outperformance, would not. For these reasons, we have not conducted our own analysis.

- 9.91 UR told us that inferences could be drawn from PNGL's MAR.³¹ UR said that the MAR had risen markedly following the 2007 determination and was above 1. We had some concerns over the reliability of the MARs in this case—see paragraph 7.61. However, notwithstanding reliability, we do not consider that a MAR of above 1 provides evidence of excess profitability in its own right because it may encapsulate investors' expectations of the company's ability to earn returns above the cost of capital for a variety of reasons, including the ability to outperform the regulatory settlement. We also note above that there may be some justification for a premium above the forward-looking WACC in this case to compensate for project-specific risk. Both these factors may explain a MAR of above 1. Further we also note that a MAR of above 1 is not unusual in the context of regulated utilities.³²
- 9.92 We found no other reliable or practicable method for evaluating via an objective measure whether distribution prices are too high, nor was one suggested to us.

Technical or other errors

- 9.93 In Sections 5 and 6, we considered whether there were any technical or other errors in the way outperformance and deferred capex had been calculated and applied. As set out in those sections, we did not find any such examples, with one exception. In regard to allowances for the treatment of business rates, as outlined in paragraphs 5.101 to 5.123, we note that there will be potential for PNGL to be funded twice for the same business rates expenses. We do not consider that funding this twice is in the public interest. We determine that an adjustment should be made to rectify this problem.

Conclusions on whether the current arrangements for inclusion of out-performance in the TRV are against the public interest

- 9.94 Two factors have been very significant in our determination. First, we have considered the purposes for which outperformance has been included in the TRV and whether those purposes are still good. Secondly, we have considered the interests of consumers. One element of the consumer interest is that revision of the TRV will lead to reductions in prices paid by consumers for gas. However, we think that the customer interest is a more complex consideration than merely whether prices could be lower. Further, if consumer interest is simply equated with price reductions, there would be few circumstances under which an approach which maintained prices

³¹ See paragraph 7.61.

³² We note, for example, the recent sale of EDF Energy Networks for a 27 per cent premium to the RAB. Source: Reuters.

rather than lowering could not be said to operate against the public interest. The consideration of the public interest is substantially more complex than that.

- 9.95 We will start with the consumer interest (drawing on the discussion of gas customers set out in Section 4). The domestic consumer interest in prices has a particular significance in Northern Ireland³³ where average household incomes are low, fuel bills are high relative to the rest of the UK, and rates of fuel poverty are much higher than in the rest of the UK. Some of this fuel poverty is likely to have arisen due to the dependence on costly oil-fired heating because of the greater cost of oil as a fuel compared with gas. In this regard, the creation of the gas distribution network so that natural gas is widely available is very important to the consumer interest. The extent of the benefit to consumers from using gas will depend on the particular circumstances (as discussed in paragraphs 4.65 to 4.84). The benefit of switching to gas can combine two factors: the lower cost of gas relative to the cost of oil, and the greater efficiency of the condensing boiler that many consumers will adopt when they change to gas. This is not dependent on gas being available, as a condensing oil boiler will deliver equally substantial efficiency benefits over a non-condensing boiler. However, once gas is available to consumers there are incentives to switch to gas and so to some extent there will be extra incentives to make a change from the status quo and so invest in a new and more efficient boiler. Customers who switch to gas and install a condensing boiler will see large benefits.
- 9.96 We looked at the effect of our determination on the prices that customers will pay. Given that there was general agreement between UR and PNGL that aspects of the pricing model (eg estimates of how demand will grow in the future, the necessary opex and capex allowances etc) will need to change, and that we have endorsed these changes, we considered that the most useful comparison would be to look at the effect of our decisions regarding the value of the TRV on how consumer prices would change. Examination of UR's financial model used for the PNGL12 determination indicates that in the absence of UR's 2012 TRV adjustment, the PNGL12 determination would have increased the cost of gas distribution for all customers by around 10 per cent compared with the prices envisaged in the PC03 determination.³⁴ Assuming that gas distribution accounts for 25 per cent for the total gas bill, the resulting increase in household and commercial customers' gas bills would be between 2 and 3 per cent. For the average household, this would have meant an increase in the gas bill by around £14 a year (when assuming a consumption of 11,427 kWh (390 therms) a year).^{35,36}
- 9.97 We now compare the effects of our adjustment to the TRV, and UR's proposals, against this baseline. Our adjustment to the TRV of £13.6 million³⁷ (and the other changes to the financial model as set out in Section 10) reduces gas distribution charges for all customers by around 2 per cent. This means that the cost of gas distribution after our TRV adjustment for all customers increases by around 8 per cent compared with the prices envisaged in the PC03 determination (with the impact on the overall gas bill being an increase of around 2 per cent). Put another way, the

³³ As discussed in paragraphs 4.53–4.64.

³⁴ Prices under the determination will increase due to various revisions (see paragraphs 9.14–9.18) which were not subject to disagreement between UR and PNGL—for example, revisions to the volume of gas consumed assumptions for 2012 to 2046. Lower rates of growth in demand are now assumed than previously on the basis of volumes that have been achieved to date. Consequently, there is less potential for revenue profiling and so an increasing proportion of revenues has to be recovered in the near future.

³⁵ 390 therms is the approximate average consumption figure expected in 2012 and 2013, as advised by PNGL. Source: UR [PNGL Price Control Draft Proposals 2012–2013 Consultation Paper](#), August 2011, paragraph 5.52.

³⁶ These estimates differ from those offered by UR—see paragraph [4.113]. The reasons for the differences are set out in the footnote to that paragraph.

³⁷ Arising from our findings that the existing arrangements for the treatment of deferred capex and the inclusion of a certain proportion of business rates outperformance in the TRV are against the public interest.

average household bill increases by around £11 a year in our decision compared with the prices envisaged in the PC03 determination. Therefore, our adjustments to the TRV lead to a saving of around £3 a year for an average household compared with the prices that would be charged with these sums being retained in the TRV.

- 9.98 In comparison, the revisions to the TRV proposed by UR would have led to an average saving of around £15 a year for an average household on the same basis. While any difference in annual household costs for natural gas is obviously a highly material consideration, and a £15 a year difference needs to be judged in the particular circumstances relevant to consumers in Northern Ireland, these differences in cost are relatively small compared with the savings obtained from a switch from oil to gas and the benefits of installing a high-efficiency boiler. However, higher costs of gas represent a cost to existing and future natural gas customers, some of whom will be from low-income or vulnerable groups. This is obviously an important consideration. Moreover, we note that the interests of domestic consumers and I&C customers in lower prices formed a major theme of the third-party responses received to our provisional determination and further consultation.³⁸
- 9.99 The position is similar for I&C customers, and in particular for those with a very sizeable use of gas. For them, higher costs for natural gas might have a significant impact, although the proportionate significance of higher absolute bills must be judged in the context of the overall size of the business. We note that higher gas charges may impact on their relative competitiveness, for example compared with industrial users in Great Britain (but overall prices, including the commodity element, are not necessarily higher than Great Britain—see paragraph 9.89). Nonetheless, the ability of I&C customers to connect to gas networks is also important in substantially reducing their overall costs. As noted in paragraph 4.90, based on PNGL’s desktop analysis and considered view of the average price paid by large I&C customers in 2011, the potential savings for its top 20 customers (by volume in PNGL’s Licensed Area), having chosen natural gas over gas oil, would be, on average, about £0.5 million a year. It acknowledged that large I&C customers had mostly switched to gas where possible. It said that there were still some potential customers such as schools, police stations, nursing homes and office blocks that had not connected but the majority of new I&C connections were now for smaller customers. However, we note that expansion of the network will allow access to natural gas for further I&C customers. As noted in paragraph 4.46, the I&C demand for gas from the planned expansion to the West could be up to 880 million kWh (30 million therms) a year (equivalent to around 25 per cent of gas volumes currently distributed by PNGL).
- 9.100 These considerations indicate that the customer interest (and by extension the public interest) is not a simple matter of present prices. In relation to current customers, and looking only at current prices, customers of course benefit if prices are cut. However, the interests of current and prospective customers in lower gas distribution costs because of a reduced TRV have to be considered in the context of the development of the Northern Ireland gas industry. Current consumers, both domestic and I&C, have benefited very significantly from the development of the network. Prospective customers will of course benefit from the existing and future development of the network. The continued development of the network remains a more uncertain business than that carried on by most regulated utilities.

³⁸ See, for example, responses to further consultation from [CCNI](#), [NEA NI](#) and the [Green Party](#). The concerns of customers were raised in similar terms in the responses to the provisional determination from: [Age NI](#); [Belfast Health and Social Care Trust](#); [Bombardier Aerospace](#); [Bryson Energy](#); [Centre for Progressive Economics](#); [ContourGlobal Solutions](#); [Manufacturing Northern Ireland](#); [Patsy McGlone MLA](#); and [Thompsons](#).

- 9.101 As well as potential for the gas distribution network to be expanded within the existing Licensed Area to infill gaps (where it is cost effective to do so), and potential for incremental expansion from the existing Licensed Areas into adjacent centres of demand, there is potential to open up new licensed areas through the building of new supply pipelines. This includes the plans for expansion to the West (see paragraphs 4.39 to 4.50), which we note DETI is actively pursuing, but could also include further developments elsewhere in the future. While some concerns were expressed as to whether expansion of the gas network should or would go ahead,³⁹ DETI told us that current policy was to ‘encourage extension of the gas network where it is technically possible and economically feasible to do so, to enhance diversity of fuel supply and customer choice and bring about reductions in CO₂ emissions’ (see paragraph 4.50) and we note that this is consistent with UR’s principal objective in carrying out its gas functions—to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland (see paragraph 2.6).
- 9.102 All these considerations demonstrate the importance of the development of the gas distribution network. It is important to bear in mind that the context of this determination is the creation from a standing start of a gas distribution network in Northern Ireland in the last 16 years. Over 162,000 customers have benefited so far, including both domestic and I&C customers. The number who would benefit from new distribution networks, incremental expansion from existing networks and infill of gaps in existing networks is uncertain. However, within the PNGL and firmus licence areas, and adjacent areas, we were told that there was the potential for up to around 290,000 further connections to natural gas (see paragraph 4.38), while plans for expansion to the West could serve up to 31,000 households as well as I&C customers (see paragraphs 4.45 and 4.46).
- 9.103 Therefore the considerations relevant to the interests of customers as they must be considered in determining whether the current price conditions operate or may be expected to operate against the public interest are not just the question of whether it would be possible to reduce current prices (or offset price increases that would otherwise occur). In considering the purposes for which outperformance was allowed and for which under-recovery was compensated by capitalization, we have focused on the significance of the risks taken by PNGL and the commensurate and necessarily heightened incentive systems applying, and we look at those risks in the context of a network that is still in the process of development. We think that decisions to allow 100 per cent of outperformance to be retained and for deferred capex to be rewarded were important in the context of a new and developing industry. This approach was consistent with the risks that PNGL faced when it first undertook its investments. We consider that customers have benefited from these investments through the successful development of a gas distribution system in Northern Ireland, and that they will continue to benefit. This remains the context in which decisions about the level at which prices are set are to be made.
- 9.104 Allowing PNGL to recover outperformance now that it could not recover at the time when it was earned remains consistent with the purpose of the rewards that were originally implemented and that in our view remain relevant to it as the developer of the network. That a network developer is provided with rewards and incentives that differ from those in the regulation of mature utilities is a necessary recognition of the risks it has accepted in undertaking to develop the industry. That it has been a successful approach is, in our view, reflected in the extent to which a gas distribution network has been delivered in Northern Ireland. The risks faced by PNGL were differ-

³⁹ See paragraphs 4.51 & 4.52, and, for example, [the Green Party](#) response to our provisional determination, and [Lord Whitty's report](#).

ent from those faced by a company in a mature utilities business. We consider that this remains relevant given that the sector is still developing with prospects of continued network growth and development. Put another way, the rules that applied in the past for the treatment of outperformance and deferred capex, which allowed PNGL to retain and not share these benefits, reflected the challenges faced by the company at that time and recognized the particular difficulties faced by PNGL. Capitalization of past outperformance into the current TRV is a reflection of that point that ensures that PNGL is appropriately rewarded (as was intended and understood) for delivering efficiencies and a successful roll-out of the network and remains incentivized to do so. While the period of greatest risk has passed, we do not think it is yet time for these considerations to be forgotten. Of course, the benefits of past investment would not be lost were elements of the TRV to be removed. In paragraphs 9.110 to 9.124, we consider the consequences of that approach.

- 9.105 We conclude that the inclusion of historic outperformance in the TRV does not operate or may not be expected to operate against the public interest. We note that the inclusion of outperformance was an important incentive element in a system of risks and rewards that has provided benefits to consumers. The benefits to customers through development of the network, and through the continuing development of the network (which could be impaired if the perception of regulatory stability was harmed—see paragraphs [9.112 to 9.120]), justify the costs and it is right that customers who benefit should pay for the costs of that network, part of which is the cost of the risk taken on by PNGL. The revenue cap for gas distribution charges could be lower, but we have to take account of all matters relevant to the public interest. It has not been shown that prices are too high by an objective measure or that prices are unduly high because of errors, and we consider that providing an appropriate reward in the context of ensuring the development of the natural gas industry in Northern Ireland is highly pertinent. We note that other elements of the determination (see paragraphs 9.14 to 9.18) will also increase prices to customers (see paragraph 9.96), but we consider that these changes are necessary and our conclusions on the public interest in respect of possible TRV adjustments remains.
- 9.106 For similar reasons, we also conclude that, for the most part, inclusion of deferred capex in the TRV is not against the public interest. This is also part of the relevant incentive mechanism that has contributed to the successful and flexible development of the network. However, we have found that in the specific case of identified 1999/2000 capex deferrals where these have not been completed by the end of PC03, these sums are against the public interest—see paragraphs 9.61 to 9.76. This is because these sums are associated with specific projects, and where we can identify that, rather than representing an efficient deferral, these have been delayed so long (and notice was given that these projects would be reviewed), we can more properly consider them as projects that are not being pursued. Because these projects were identified in 2006 for review, we can conclude that from this date it was appropriate to consider these projects as not compatible with PNGL's capex strategies. We therefore consider it appropriate to remove from the TRV financing benefits arising on these projects since 2007. We also consider it appropriate to remove the project management allowance associated with these projects. We also consider it appropriate to remove the allowance from the TRV, but we note that because these were offset against future capex allowances, this will not itself affect the amount customers pay.
- 9.107 We also conclude that the fixed pre-tax real rate of return for PNGL over the period 2012/13 of 7.5 per cent does not operate against the public interest for the reasons set out in paragraphs 9.19 to 9.37, and because it similarly represents part of the appropriate returns to PNGL for its past activities.

- 9.108 In reaching our conclusions on whether the inclusion of historic outperformance and deferred capex in the TRV operates or may be expected to operate against the public interest, we do not consider that we are taking a fundamentally different view of the public interest from UR. Where we differ from UR is where, within that overall view of the public interest, we strike the necessary balance between prices that customers pay, network development, and the appropriate reward for the development of the network in the context of a still maturing industry.
- 9.109 UR proposed that, if we did not agree that the TRV should be revised, other steps could be taken to resolve the public interest issues it had identified. UR proposed that any reduction in the TRV might instead be introduced in the future rather than immediately. For the reasons we have given above, the only revisions that need be made to the TRV are those that should be made now. We should observe, however, that our decision covers only two years and we do not wish to trespass on to the territory of future regulatory reviews (where other issues or evidence may be relevant). This is especially the case in a decision such as this where the specific context has been highly important to our reasoning. We do not find UR's objections to the current situation based on comparisons with a conventional RAB-based system—or its proposal to allow PNL to recover the value of outperformance at the appropriate rate for just one regulatory cycle—persuasive. For the reasons set out in paragraphs 9.19 to 9.37, we do not consider that the current rate of return is against the public interest and so do not consider that there are grounds to consider a reduction in the rate of return as proposed by UR (paragraph 9.19).

Proposals to remove elements of the TRV and other actions to reduce prices

- 9.110 Because UR determined that removal of historic outperformance and deferred capex from the TRV would be appropriate, there has been a vigorous debate about the adverse consequences of revising the TRV. Although our conclusions on whether the current price control conditions were against the public interest meant that the TRV need not be revised (except with respect to some adjustments to deferred capex for 1999/2000 deferrals uncompleted by the end of PC03, the associated capitalized financing and management fee and an adjustment to business rates outperformance), we will, in acknowledgement of the arguments made, consider whether the consequences of removing outperformance and deferred capex would have adverse consequences.
- 9.111 The following two considerations would have been important:
- (a) whether these actions would create a perception of regulatory instability and whether this would have a significant effect in deterring future investment and/or increase the cost of future funding of existing and additional investment in gas distribution and other regulated sectors in Northern Ireland; and
 - (b) what the effect on future network expansion might be.

Expectations and regulatory stability

- 9.112 The regulatory process involves the adoption of approaches and methodologies to allow the regulator to set price controls. The appropriateness of price controls is assessed with reference to the regulator's objectives. Consequently we would expect UR, as part of the normal regulatory process, to revise and refine its regulatory approach in accordance with changing circumstances and the ongoing balancing of objectives. Because regulators make their decisions anew at each periodic review, there will be no expectation that all elements of the regulatory framework will remain

unchanged from review period to period. In line with normal regulatory practice,⁴⁰ our view is that any revision of previous regulatory determinations should be: well reasoned, properly signalled, subject to fair and effective consultation, clear and understood, and, normally, forward-looking. We consider that some changes are more serious than others, and that to reduce ex post and without clear signalling the opening value of a RAB is a step that should not normally be taken without very good justification, and only then after an appropriate period of consultation on the proposals. The RAB is an important aspect of the credibility of a regulatory regime in that it provides investors with a qualified assurance that they will be able to earn an assured return. Having said that, our own decision in the reference indicates that RABs can and should be changed where justified in the public interest. Regulators are free to depart from previous decisions where appropriate in pursuit of their statutory objectives, but they should consider carefully whether their actions may be considered to lead to regulatory instability that will add to uncertainty in the industry. This is discussed in Section 8.

- 9.113 UR's 2007 determination is relatively recent. In a situation where the regulatory regime changes significantly (as a result of the 2007 determination), and where the regulation is of a still-developing industry, it is not unexpected if aspects of the new regime need to be further clarified in subsequent determinations. Nevertheless, even if we found that the current arrangements were against the public interest, we would have to weigh up very carefully any adverse effects that might be expected to result from making significant changes to the TRV.
- 9.114 In general, a regulatory regime should provide incentives to reduce costs and to innovate and, in PNGL's case, also to develop the gas industry in Northern Ireland. Regulatory stability is particularly important in the context of natural gas in Northern Ireland given that this is not a fully mature industry, and that future investment in network expansion is expected and desired. If it is perceived that adjustments might be made after, for example, efficiencies have been achieved which then impact on investors' prior expectations, there is the possibility, if not more, that such incentives will be blunted in future.
- 9.115 In contrast to the case for the deferred capex projects from 1999/2000, a cause for concern is whether UR gave sufficient notice or sufficiently consulted on its proposal to revise the other elements of the TRV. While UR said it indicated that it intended to share historic outperformance (referring to a reference to following best practice in its 2006 consultation document), we consider that it gave no public indication in the 2007 determination (nor any indication until 2011) that it did not intend to allow historic outperformance to remain in the TRV. Any intention to revise the historic outperformance in the OAV that it may have formed appears inconsistent with its actions and statements at that time, which point more towards the OAV having been established and fixed. It is difficult to see how PNGL and its investors could have anticipated these proposals ahead of UR's consultation on the issue in 2011 (see paragraph 8.85).
- 9.116 A reduction in the TRV, with its consequent effect on the expectations of both PNGL and its investors, can have an impact on the perception of regulatory stability and can damage investor confidence in the regulatory framework. While the circumstances of this decision are specific to the special situation of PNGL (for example, the significant

⁴⁰ See, for example, [BIS, Principles for Economic Regulation, April 2011](#). Under 'Principles for Economic Regulation' (p5), it says in relation to predictability: 'the framework for economic regulation should provide a stable and objective environment enabling all those affected to anticipate the context for future decisions and to make long term investment decisions with confidence' and 'the framework of economic regulation should not unreasonably unravel past decisions, and should allow efficient and necessary investments to receive a reasonable return, subject to the normal risks inherent in markets'.

revenue under-recoveries and the move to RAB-based regulation), investors may perceive that there could in future be further compromise on principles of good regulation. That the regulatory asset value provides a basis for evaluating future returns is an important principle. We do not agree with UR that investors will recognize this as a one-off decision because of the particular circumstances in hand that has no wider ramifications (in particular, because the ratings agencies told us that their assessment of the regulatory regime would take account of the regulator's past decisions). Investors may anticipate that in addition to normal commercial risks there could be greater uncertainty in the future about the regulatory environment, and thus increased risks that returns on investment will not be realized in the way or to the extent that is expected. The effect of this could also be to risk an increase in the cost of debt (or prevent or slow any reduction in the cost of debt for Northern Ireland utilities that would otherwise have occurred).

- 9.117 Evidence provided to us by Fitch and Moody's shows that the agencies place considerable weight on regulatory stability and that Fitch put PNGL on negative watch shortly after UR's decision. As noted in paragraphs 8.42 and 8.43, in May 2012, Fitch removed PNGL's IDR and senior unsecured rating from rating watch negative, but maintained that the outlook on PNGL's Long-Term IDR was negative pending the outcome of the CC proceedings, and/or further evidence related to the development of the regulatory regime. Even without a revision of a credit rating, a higher premium may nevertheless be demanded by debt investors for future debt issues in the gas sector in Northern Ireland if there were to be an increased perception of regulatory instability. There may also be an effect on the cost of equity, although it is harder to gauge to what extent equity investors will require increased returns.
- 9.118 We recognize that such concerns should be qualified by the comfort investors can take from the terms of the regulatory regime, in particular the duties of the regulator and the role of the CC under the regime, and in this case by the nature of the issues themselves. Investor confidence might nevertheless be weakened if the regulator is perceived to behave inconsistently, and so the expectation will be established that where a regulator has behaved in this way in the past, there is a risk that it will do so again in the future. In this way, the cost of capital might be increased. Moreover, there could also be an effect on the perception of regulatory stability for other regulated sectors in Northern Ireland. There could, for example, be some impact within the electricity sector, which is also regulated by UR. Any impact on the electricity sector could be important given the much larger size of the RAB for NIE. Given the importance of conversion from oil to gas in addressing the interests of Northern Ireland consumers (and also taking account of the importance attached by DETI to the development of the gas network for various policy reasons), we would have attached considerable weight to any material risks of deterrence of future investment or increasing the costs of financing it.
- 9.119 UR said that it had seen no indications that its proposals to revise the TRV would deter further interest in the gas sector in Northern Ireland. For example, it presented evidence (such as letters expressing interest) from various companies—see paragraph 8.31. We gave this evidence careful consideration but concluded that it was of limited strength, as the expressions of interest were either at a very high and 'in principle' level, or did not refer to regulated sectors of the gas industry, or were somewhat qualified over concerns about regulatory stability.
- 9.120 We are not able to quantify the effects of a lack of regulatory stability, but we consider that the qualitative evidence (including that received in certain third-party submissions) suggests, notwithstanding the statutory position and the right of appeal, that such an effect exists and that it is not so small that it can be disregarded. Any

increase in the cost of capital would feed through into relatively higher prices to customers.

The extent of future network expansion

- 9.121 As set out in paragraphs 4.29 to 4.50, possible expansion of gas supply in Northern Ireland includes extension of the network within existing Licensed Areas by PNGL and firmus to infill unsupplied areas, potential incremental expansion from the existing Licensed Areas into adjacent areas, and also the development of new distribution networks. In particular, expansion to the West via a new supply pipeline is under active consideration. Additionally, it is possible that other new expansion opportunities may be identified.
- 9.122 While we cannot determine the extent of these future expansions, they are possibilities, and whether they go ahead depends on many factors (including the costs of funding expansion and investors' willingness to invest, but also factors such as the relative cost of fuels, government policy and willingness to promote expansion for economic, social and environmental reasons, and so on). However, the scale of these expansions could be large—see paragraphs 4.31 to 4.37 and 4.45 and 4.46.
- 9.123 Any impact which reduces the extent of network expansion, or particularly the development of new supply areas in Northern Ireland, implies a large opportunity cost for future customers who would otherwise benefit from the ability to convert to natural gas. The process for the next expansion of the gas network in Northern Ireland is already under way, and the negotiation of licences and arrangements may be hampered by a concern that UR could overturn aspects of the agreement at a later date. This is consistent with what we have been told about the government objectives for the gas sector, as it is seen as offering benefits in a variety of ways, eg a joint DETI/UR publication states:

The Northern Ireland authorities are keen to develop a natural gas market in Northern Ireland and in particular in the West of Northern Ireland for a number of reasons, including the environmental benefits of switching to gas via reduced carbon emissions, the increased fuel choice and savings for consumers, the diversification of energy sources and to make the province more attractive from the perspective of overall business investment, including foreign investors.⁴¹

Conclusions on proposal to remove elements of the TRV

- 9.124 We have carefully considered UR's suggestions that failure to remove elements of historic outperformance and deferred capex will not be in the public interest. While it is clear that prices to existing customers would reduce, we also note that there is a substantial risk that the consequences of such measures would be to reduce the willingness of investors to invest in future development of the gas network (and possibly other regulated sectors in Northern Ireland) and could increase the cost of capital applying. This could in turn increase costs for financing current and future activities (in the case of PNGL, this may apply after the period of a fixed rate of return is replaced, possibly with a WACC-reflective arrangement). Therefore we consider that this could impede future gas network development which could otherwise create substantial future benefits for future customers, and could increase costs for current and

⁴¹ Source: *Potential extension of natural gas and related services in Northern Ireland*. Feasibility Study Summary Report, March 2010, p9.

future gas consumers. These outcomes could also apply to other regulated sectors in Northern Ireland.

Final determination

- 9.125 We conclude that the existing price control arrangements are not in the public interest and should be modified as outlined above.
- 9.126 We agree with the proposed revisions for opex and capex allowances made by UR, as well as the other changes made by UR in the PNGL12 determination, except for UR's TRV adjustment. For the reasons set out above, we conclude that no revision should be made to the TRV, except to reflect the 1999/2000 capex deferrals that were not completed by the end of PC03 (including post-2006 capitalized financing benefits), together with an appropriate management fee of 5 per cent. We estimate this value at £8.6 million (see paragraph 6.72).
- 9.127 In addition, an adjustment should be made to the TRV for funding PNGL twice for the same business rates expense. We estimate this value at £5 million (see paragraph 5.118).

Licence modifications

- 9.128 We are required by article 15(1)(bb) of the Gas Order and by our terms of reference to report on whether the matters which we have found operate, or may be expected to operate, against the public interest could be remedied or prevented by modifications of the relevant licence conditions.
- 9.129 We have found that in Condition 2.3 (Conveyance Charges), the following modifications⁴² should be made:
- The value of TRV should be adjusted to reflect the 1999/2000 capex deferrals that were not completed by the end of PC03 (including post-2006 capitalized financing benefits), together with an appropriate management fee of 5 per cent. We estimate this value at £8.6 million (see paragraphs 9.72, 9.74 and 9.126).
 - An adjustment should be made for the effects of funding PNGL twice for business rates allowances. We estimate this value at £5.0 million (see paragraphs 9.93 and 9.127).
 - Modifications to give effect to the changes detailed in PNGL12 (with the exception of UR's proposed TRV adjustment of £74 million, instead implementing the two changes identified in the preceding bullet points) which include, for example, updated amounts for capex and opex (including a proportion of the costs incurred and borne by PNGL in this investigation) and which should result in PNGL's allowed revenues for 2012 and 2013 being £43.340 million and £44.688 million respectively (in 2010 prices) (see paragraph 10.26).
- 9.130 Under article 17(3) of the Gas Order, UR is now required to give notice of the modifications to the relevant conditions of PNGL's licence UR proposes to make for the purpose of remedying or preventing the adverse effects we have specified in our report. After considering any representations or objections made to these proposals,

⁴² In our view, 'modifications' includes changes to values in the licence as well as changes to the wording of the licence.

UR must notify the CC of the proposed modifications and of the reasons for making the modifications.

- 9.131 Under the procedure set out in the Gas Order, the CC then has four weeks in which, if necessary, to direct UR not to make some or all of the proposed modifications, and to propose different modifications, which seem to the CC requisite for the purpose of remedying or preventing adverse effects specified in the CC's report.

Financeability

- 9.132 Our consideration of financeability is set out in Appendix G. We found that the analysis that UR performed at the time of its PNGL12 decision sufficiently demonstrates that PNGL is financeable for the duration of the PNGL12 charge control even if UR's 2012 TRV adjustment is made in full. It follows that, as the adjustment to the 2012 opening TRV in our redetermination is less than the adjustment that UR made to the 2012 opening TRV, PNGL is also financeable for the duration of the PNGL12 charge control in our decision.

10. Adjustments to the financial model and recommendations

Overview

- 10.1. In this section we set out the changes we made to the financial model used by UR in the PNGL12 determination in order to calculate PNGL's revenue cap following our determination, ie it incorporates our decision as to the 1999/2000 capex deferrals, business rates outperformance and the removal of UR's proposed 2012 TRV adjustment (as well as the correction of a minor calculation error). We also decided, in making these changes, to what extent it was reasonable to take into account the costs PNGL incurred or bore as part of this inquiry.
- 10.2. We then set out the revised revenue cap for PNGL for 2012 and 2013.
- 10.3. We also briefly comment on other changes related to the financial model that were suggested to us or that we identified as part of our determination, but that we decided not to make.
- 10.4. Finally we provide some recommendations for UR to consider in its next charge control determination.

Modelling changes

- 10.5. We set out in detail below the input changes we decided to make to UR's PNGL12 financial model. We also set out the resulting impact on prices and revenues.
- 10.6. First, we set out the changes that we made following our determination not to make the 2012 TRV adjustment proposed by UR in full and instead to make an adjustment for those 1999/2000 capex deferrals that were not completed by the end of PC03 and to business rates outperformance (see paragraph 9.129). After that, we set out any other changes we made to the financial model either as a result of submissions made to us during our determination or as a result of our work with the financial model.

Modelling changes to implement our determination on the 2012 TRV adjustment

- 10.7. As set out in paragraphs 9.125 to 9.127, we decided that the 2012 TRV should be reduced by £8.6 million for the 1999/2000 capex deferrals that were not completed by the end of PC03 and that a (downward) adjustment of £5 million should be made to business rates outperformance.
- 10.8. We did not find the inclusion of other elements of the TRV to be against the public interest. Therefore we concluded that we would not make the rest of the 2012 TRV adjustment that had been suggested by UR.
- 10.9. We therefore removed UR's £74 million 2012 TRV adjustment from the financial model and replaced it with our determined TRV adjustment of £13.6 million.¹ These changes increased PNGL's allowed charges (and revenues) by 8.4 per cent compared with UR's PNGL12 determination.

¹ The TRV consists of a number of different components (eg the depreciated asset value (DAV—which is effectively the 2006 TRV plus capex since 2007 net of depreciation), the profile adjustment (PA—which 'logs up' revenues that are deferred into future years and ensures that PNGL recovers all its allowed revenues by 2046) and working capital). We therefore need to decide which of these components our TRV adjustment should be allocated to. We decided to allocate it to the DAV, as this is where the elements of the TRV that we adjusted (deferred capex and business rates outperformance) were originally recorded. Submissions from UR and PNGL also indicated that making the adjustment to the DAV was appropriate.

Working capital

- 10.10. PNGL said that movements in working capital and capital creditors were not in the correct cost base (they were in 2006 prices rather than 2010 prices). UR agreed that these numbers should be rebased to 2010 prices.
- 10.11. We therefore made the relevant change to the financial model. This change reduces PNGL's charges (and revenues by 0.05 per cent).

Costs of the inquiry

- 10.12. We have allowed PNGL additional opex costs to cover the costs it has reasonably incurred or borne in respect of our inquiry. In doing so, we have taken into account the principles applied by statute in equivalent price-control references in other utility sectors² and the general principles of proportionality³ and materiality.⁴
- 10.13. PNGL said that UR's PNGL12 determination did not include the cost it incurred in relation to our investigations and our determination. PNGL requested that we should make an adjustment to the opex costs assumptions to allow PNGL to recover the costs it had incurred as a result of this process.⁵ PNGL said that it was implausible that its existing legal and professional fee allowance included an allowance for the cost of our determination. This was because its allowance for legal and professional fees was based on the actual legal and professional fees incurred over the last price control and this did not include an appeal to the CC.
- 10.14. UR said that only costs that PNGL efficiently incurred in relation to our determination should be included in PNGL's opex allowance for legal and professional fees. UR said that including PNGL's cost of our determination in PNGL's opex and capex allowances would mean that PNGL earned a return on these costs (and until 2016 at 7.5 per cent (which was higher than PNGL's cost of capital)), which would be expensive.
- 10.15. We make no allowance for PNGL's own internal costs such as resource and management time dedicated by PNGL to the investigation, or travel and subsistence costs. We have only allowed costs from the date of the reference (28 March 2012) to the date of the final determination; we have made no allowance for costs which PNGL incurred up to the date of UR's determination (10 January 2012) or between that date and the reference being made. On this basis, PNGL said that its cost for external advisers—for solicitors, legal counsel and economic advisers—in relation to our determination was £2.02 million.
- 10.16. In deciding what costs PNGL had reasonably incurred, we considered whether the costs claimed were proportionate to the sums at stake in this reference (mainly the £75 million TRV adjustment proposed by UR) and whether they had been incurred solely for the purposes of our investigation. We were satisfied that the costs were relevant and proportionate.
- 10.17. We considered UR's representation that we should decide what costs PNGL had efficiently incurred. We decided that such an efficiency test is appropriate where the parties themselves were able to control the scope of the work done. However, in a price control investigation, the scope of the work done is largely determined by the

² For example, by section 12(3A) of the Water Industry Act 1991.

³ ie that the costs incurred were proportionate to the sum at stake for PNGL.

⁴ ie that the costs incurred were incurred solely for the purposes of our investigation.

⁵ PNGL [response to provisional determination](#), paragraphs 9.1–9.3.

CC, not the parties, as it is the CC that decides which matters it wishes to consider in depth, what detailed evidence the parties must provide and on what matters the parties are to make submissions. We did, however, disallow costs incurred in preparation for the investigation before it started, and we also made a proportionate adjustment with regard to the extent to which, in our view, our determination had supported PNGL's (rather than UR's) claims in relation to the determination.

- 10.18. On some matters, UR and PNGL were in agreement. Where the parties' claims differed, our determination has supported both UR's and PNGL's claims to some extent. On the major issues of difference, we have in the main supported PNGL's views more than UR's but we have not accepted all PNGL's arguments or endorsed all its views. In some cases, such as treatment of the 1999/2000 capex deferrals, we have found against it. Overall we decided that it was reasonable to take into account in our determination two-thirds of PNGL's costs.
- 10.19. We have therefore decided to add £1.347 million (in 2012 prices) to PNGL's opex allowances for the costs it has incurred in our investigation.⁶
- 10.20. We decided to include these costs as an addition to the professional and legal fees that are included in PNGL's opex allowance in 2012, because we think that UR's PNGL12 determination did not envisage our determination and would therefore not have included any costs for our determination in the allowances for legal and professional fees.
- 10.21. We note that this means that PNGL recovers these costs over a period of 35 years and will receive a return on these costs. However, had we included these costs as a one-off payment to PNGL in 2012, this would have increased the distribution charges payable by customers by a further 3 per cent in 2012. Given the high level of fuel poverty in Northern Ireland, we thought it therefore preferable to determine a longer recovery period (which means that costs only increase by 0.15 per cent in 2012).
- 10.22. This change increases PNGL's charges (and revenues) by 0.15 per cent.
- 10.23. Under PNGL's licence, it is required to pay an annual fee to UR. There are arrangements within the licence for the recovery of costs through this annual fee, for UR and GCCNI's (1.14.3(a) and (b)) overall costs,⁷ and the CC's (1.14.3(c)) reference costs.

Condition 1.14: Payment of Fees to the Authority⁸

In respect of each year, beginning on 1 April, during which the Licence is in force, the Licensee shall pay to the Authority a fee of the amount determined in accordance with this Condition (the **licence fee**)

The Licensee shall pay the Authority the licence fee for each year (the relevant year) within 30 days of the Authority giving notice to the Licensee of the amount due from the Licensee for the relevant year.

For each relevant year, the licence fee shall be the total of:

- (a) an amount that is the Relevant Contribution to the Estimated Costs of the Authority for the relevant year;

⁶ Rebased into 2010 prices (from 2012 prices), that is £1.242m. The allowances and price determinations are modelled using figures expressed at constant 2010 prices.

⁷ This was capped at £500,000 (from 1 April 1997) but adjusted from September 1996 annually by reference to the retail price index" (Cond. 1.14.3(d)).

⁸ Text as modified by UR's Notice of 28 September 2012.

- (b) an amount that is the Relevant Contribution to the Estimated Costs of the Consumer Council with regard to the exercise of its functions relating to gas consumers for the relevant year;
- (c) an amount that is the Relevant Contribution to the Estimated Costs of the Competition Commission, in connection with any reference made to it in respect of the Licence or any other licence granted under Article 8(1)(a) of the Order, for the year immediately preceding the relevant year (the **previous year**);and

...

In this Condition:

- “Estimated Costs”
- (i) in relation to the costs of the Authority, means the costs estimated by the Authority as likely to be its costs for the relevant year as calculated in accordance with the Principles;
 - (ii) in relation to the costs of the Consumer Council, means either:
 - (A) the costs notified to the Authority by the Consumer Council as its estimated costs for the relevant year as approved by the Department; or
 - (B) ...
 - (iii) in relation to the costs of the Competition Commission, means the costs estimated by the Authority following consultation with the Competition Commission as likely to be the costs of the Competition Commission for the previous year in connection with references of the type referred to in sub-paragraph 3(c) above.
- “Principles” means the principles determined by the Authority for the purposes of this Condition generally, following consultation with the Licensee and with others likely to be affected by the application of such principles and as notified to the License in writing.
- “Relevant Contribution” means, in respect of the Estimated Costs, the level of contribution to those costs applicable, whether by way of a specified amount or a stated proportion, to the Licensee as determined under or in accordance with the Principles.

10.24. Therefore, UR’s costs in respect of this investigation would be recovered through the licence fee (unless these are above the cap). The costs to be charged will depend on the proportion of its total annual costs UR has determined are attributable to PNGL’s licence, and similarly what proportion of CCNI annual costs UR has determined are attributable to PNGL’s licence. The costs of the work relating to this reference will be

a part of these costs. Similarly UR can pass through an amount for the CC's reasonable costs.

- 10.25. It will be for UR to determine what costs are therefore included in the licence fee to PNGL in respect of this investigation and we therefore do not make a determination on these costs. The licence fee is a pass-through cost which can be adjusted retrospectively⁹ to reflect the actual fee levied on PNGL by UR and we therefore do not need to make any changes to the financial model to reflect these costs at this time. We note that these costs will ultimately be borne by PNGL's customers.

PNGL's allowed revenues for 2012 and 2013

- 10.26. Following the adjustments to the financial model, we determine that PNGL's allowed revenues for 2012 and 2013 are £43.340 million and £44.688 million respectively (in 2010 prices).¹⁰

Other suggested or possible changes that we did not implement

- 10.27. In this section, we briefly describe other changes that we considered, or which were suggested to us during our determination, but that we decided not to implement in the financial model.

Actual data

- 10.28. PNGL said that it was not appropriate and proportionate to update the financial model with updated forecasts or additional actuals. PNGL said that the charge control lasted only for two years and the first year would almost be completed by the time our determination became effective. Actualization of data could be dealt with under the recognized retrospective mechanisms at the time of UR's next price control review.
- 10.29. UR said that it would prefer us not to make any updates to the model for actual data that became available since the PNGL12 determination in January.
- 10.30. Since UR's PC2012 determination in January 2012, more up-to-date data will have become available that could inform our determination (for example, 2011 regulatory accounts are now available and PNGL will have actual out-turn performance data for the first half of 2012). However, given that we have not undertaken an in-depth review of UR's modelling assumptions other than the rate of return and the 2012 TRV adjustment, we think it would be disproportionate to do so now for the purpose of calculating PNGL's revised revenue cap. We also think that the short duration of the charge control, UR's retrospective mechanism and UR's general approach to actualization of data further reduce the need for us to update UR's other modelling assumptions. We therefore did not update the financial model for data that has become available since UR's PNGL12 determination (other than for the adjustments set out in paragraphs 10.5 to 10.11 above).

Efficiency assumptions

- 10.31. PNGL said that UR's additional blanket 1 per cent efficiency assumption for opex and capex was inappropriate, given that efficiencies had already been taken into account

⁹ UR PNGL12 determination, paragraph 5.17.

¹⁰ This is 8.5 per cent more than in UR's PNGL12 determination.

in the opex and capex forecasts that were included in the financial model, and there was therefore no justification for further savings to be assumed.

- 10.32. We think that regulators usually make efficiency assumptions over and above their explicit opex and capex forecasts when setting charge controls. PNGL has not provided any supporting evidence for its assertion that the 1 per cent efficiency assumption is incorrect. We are also of the view that it would be disproportionate for us to further review the appropriate level of efficiencies for 2012 and 2013, given the short duration of the charge control and the resulting small impact that a reduction in the efficiency assumptions would have on PNGL's revenues.

Use of COPI index

- 10.33. Manufacturing Northern Ireland (MNI) suggested that the Construction Output Price Index (COPI) price index should be used (rather than the RPI) to index capex allowances during PNGL12. MNI said that as a result of the recession the cost of construction and related works in Northern Ireland had fallen significantly due to overcapacity and increased competition.
- 10.34. PNGL said that there may be a number of disadvantages of COPI relative to the RPI. For example, it was not clear that the wide range of construction inputs within the index would be appropriate for PNGL and whether the important inputs for PNGL were adequately reflected in this index. COPI appeared to be much more volatile than the RPI, which could result in unnecessary price fluctuations for customers.
- 10.35. UR said that it did consider using COPI to index capex allowances during PNGL12, but concluded that the RPI remained a suitable index for capex allowances since the use of the RPI provided a more certain link between costs and allowances for PNGL, given that its contract with its main capex contractor, McNicholas, was linked to the RPI (which reduced risk to PNGL). UR said that there were also recognized problems with the use of COPI instead of the RPI. For example, COPI was not considered to be a robust index in its own right, as demonstrated by the UK Statistics Authority's 2010 decision to withdraw its designation as a national statistic. In terms of practicality and simplicity, the RPI scored slightly better on the grounds that it was published in a more timely manner and was not subject to retrospective revision like COPI. It was also easier for companies to source forecasts of RPI than it was to forecast COPI, which would aid companies in their business planning processes.
- 10.36. From the evidence provided, we did not think that it would be appropriate for us to specify the use of COPI instead of the RPI for indexing capex allowances in PNGL12.

Depreciation assumptions

- 10.37. The 2012 financial model includes an assumption that the 2012 opening DAV is depreciated over a period of 34 years. This is despite the licence period running for another 35 years. However, changing the depreciation period from 34 to 35 years does not have any impact on the charges paid by customers. Therefore we do not correct the depreciation assumption in the financial model.

Working capital

- 10.38. PNGL said that there appeared to be an anomaly in the movement of regulated working capital between 2011 and 2012 which could be related to the incorrect inputs

being used. (We note that working capital movements were £1.6 million in that year compared with movements of around £0.3 million a year in subsequent years.)

10.39. The movement of regulated working capital between 2011 and 2012 was solely used in UR's financeability assessment. We do not consider that the potential error pointed out to us is material in the assessment of PNGL's financeability (as there was only a difference of around £1 million in the working capital movements in 2012 compared with the subsequent years). We note that with the adjustment of the price base for working capital (see paragraphs 10.10 and 10.11) this difference has reduced further.

Recommendations

10.40. Below we set out a number of recommendations for UR's next charge control determination for the period covering 2014 to 2018. We have not implemented these recommendations in our determination as we think that these proposals either should be subject to a formal consultation process or because they have a relatively minor impact on the charges paid by customers in the PNGL12 charge control, particularly considering the short duration of two years of the current charge control. However, we do encourage UR to consider these recommendations in the charge control process covering the period 2014 to 2018.

10.41. Our recommendations are:

- (a) UR to review the appropriateness of the timing assumptions for cash flows in the financial model, in particular the end-of-year assumption for PNGL's opex, capex and revenue-related cash flows—see paragraphs 10.42 to 10.46;
- (b) UR to review the appropriateness of PNGL's connections incentives—see paragraphs 10.47 to 10.50; and
- (c) other recommendations—see paragraphs 10.51 to 10.55.

Timing of cash flows

10.42. PNGL said that its actual revenue profile over the course of a year was largely volume dependent and that since gas demand was seasonal, revenue recovery was generally weighted towards the first and last quarters of a calendar year. PNGL said that its actual opex and capex profile was generally evenly spread throughout the year. PNGL said that these actual cost and revenue profiles would tend to mean that positive cash flows were generally weighted towards the first and fourth quarters, and negative cash flows towards the middle quarters.

10.43. UR said that the regulatory (ie financial) model assumed that all income and expenditure was received at the year end. This did not accurately reflect the actual timings of cash flows to PNGL. It said that the timing assumption for cash flow was set out in PNGL's licence (condition 2.3.15(b)) and any change to the assumptions would require a change to the licence, but that a semi-annualized WACC approach was more conventional and more natural.

10.44. PNGL said that it would not expect that there would be any significant impact on prices, or on the overall value to be recovered by the company, as a result of changing the financial model to reflect the timing of cash flows. UR said that a change in the timing assumptions for the annual cash flows would be to bring forward by six months the discounting of net cash flows over the remaining period to 2046, which would reduce conveyance charges by around 1.5 per cent.

- 10.45. We think that the current model assumption that cash flows in each year occur at the end of the year does not reflect how, in reality, these cash flows are received by PNGL. The result of this assumption is that PNGL effectively receives slightly higher revenues than necessary. We think that assuming that revenues are received in the middle of the year is a more realistic and pragmatic assumption and UR should therefore consider changing its modelling assumptions (that cash flows are received by PNGL at the end of the year) when setting the next charge control (following the necessary consultation of stakeholders).
- 10.46. We have not implemented this change ourselves. It was not a point that UR consulted upon in its PNGL12 determination. We considered that the potential detriment to customers from deferring a change to the methodology until UR's next charge control determination is relatively small given the short duration of the charge control, and saw benefits in UR consulting on such a potential change to the calculation methodology before implementing it.

Connections incentives

- 10.47. PNGL under the 1996 licence had strong incentives to connect customers to the network as the regulatory system set a price rather than revenue cap. Consequently additional customers represented an increase in revenue to PNGL. When the system moved to a revenue cap, this direct incentive was lost. The 2007 determination originally envisaged a connection incentive that was similar to the volume incentive PNGL faced under the 1996 licence: 'As part of the review we have agreed to move from a price cap regime to a revenue cap whereby we set allowed revenue rather than allowed prices. The removal of the volume incentive will be counterbalanced by a connections incentive of similar magnitude.'¹¹
- 10.48. It appears to us that the connections incentives in PNGL12 are not of the same magnitude as the previous volume incentive. This is because PNGL is currently only exposed to limited financial penalties (or rewards) if it underperforms (outperforms) its connections targets as:
- (a) PNGL's exposure to capex risk is low, because PNGL's capex allowance is adjusted ex post for the actual number of connections.
 - (b) PNGL's exposure to revenue risk is low, because PNGL only receives a variable allowance of around £2.2 million a year through the Advertising, Marketing and PR mechanism, which is linked only to the actual out-turn of new domestic owner occupier¹² connections (with no variable elements for other types of connections), whereas previously PNGL was exposed to revenue risk relating to the volume of gas consumed by all (new and existing) customers.
- 10.49. We considered whether stronger incentives would be appropriate to promote the development of the gas network in Northern Ireland, but we have not opined on this because our focus is the licence arrangements and price determination for PNGL, whereas this appears to be a broad policy question which, if appropriate, might be delivered through various incentives applying to PNGL, gas suppliers or customers.
- 10.50. However, we recommend that UR undertake an analysis whether it is indeed the case that the connections incentives in PNGL12 are not of the same magnitude as

¹¹ From the Executive Summary of UR, Phoenix Natural Gas Price Control Review 2007–2011, Annex 2: Distribution Expenditure Final Determination, November 2007, p i.

¹² UR said that this referred to connections of domestic properties that are not New Build or NIHE properties (so it includes privately-rented accommodation)—see UR [PNGL12 determination](#), p5.

the previous volume incentive. Should this be the case (ie should it turn out that the connections incentive is not of the same magnitude as the previous volume incentive), we recommend that UR consider (and consult on) whether it is in the public interest to make changes to the connections incentives or any other part of the regulatory framework as a result of this analysis.

Other recommendations

Capex in 2007 to 2011

- 10.51. The financial model does not include capex in the period 2007 to 2011 in the DAV calculation. This is inconsistent with the treatment of capex in the period after 2011. Although the impact on the charges paid by customers is immaterial in the current charge control, we think that it will become more material over time. We therefore suggest that UR review this treatment as part of the next charge control determination.

Transposition errors (capex overspend)

- 10.52. PNGL said that the 2009 capex overspend should be added to the DAV in 2014 as allowed under the capex rolling incentive mechanism. This overspend had been correctly taken into account when calculating depreciation in each year but had failed to be included in the DAV. UR agreed that an addition should be made to the DAV in 2014.
- 10.53. We do not consider that this error is material as it is less than 0.1 per cent of PNGL's TRV (around £0.3 million out of a total TRV of around £0.4 billion). We also note that this error only impacts on the TRV in 2014, ie after the end of the current control period. We therefore did not make a correction for this error, but we think that UR should consider whether it would be appropriate to make the associated adjustments in its next determination.

Errors in the TRV adjustment for the prepayment meter allowance

- 10.54. UR said that PC02 capex allowances included a prepayment meter allowance based on 13 per cent of forecast P1 connections. However, UR said it had incorrectly calculated this allowance as 13 per cent of actual P1 connections. As actual P1 connections were 9,294 fewer than forecast P1 connections, there was therefore an error of £147,224 (in 2006 present value terms and prices; or £237,997 in present value terms at the end of 2011, and 2010 prices). Therefore the 2012 opening TRV should be adjusted down by this amount.
- 10.55. We have not assessed this potential error, but we have noted that its impact is very small at less than 0.1 per cent of PNGL's TRV (around £0.2 million out of a total TRV of around £0.4 billion). We recommend that UR consider whether it would be appropriate to make the associated adjustments as part of its next determination.