OFGEM SEGMENTAL STATEMENTS REVIEW

BDO LLP – FINAL REPORT – NON-CONFIDENTIAL VERSION | 16 January 2012

CONTENTS

02. EXECUTIVE SUMMARY

02. EXECUTIVE SUMMARY
A. Transfer pricing

02.A.1 Describe the transfer pricing methodology used by each firm.

Most groups follow a broadly similar business model with a single body trading with the markets, through which the generation divisions sell power or capabilities and from which the supply segments acquire power and gas. However, within this model there are significant differences in how functions are located between divisions and how they interact.

The main variations are:

- Some generation divisions sell either their production capacity at fixed rates, or use a complex system of options over production to hedge their output
  - this gives a return to the generation division that is independent of the electricity volumes actually produced
  - the trading body, or supply segment, receives the benefit or cost of market movements
- In other cases the central trading body acts more like a broker, standing between the generation and supply segments and the wholesale markets/counterparties

Pricing of these transactions is in most cases based on the prices reported for market trades. This is typically either set to use a separate buy and sell price or to allow a transaction fee or premium for the trading body.

In other cases a measure of costs actually incurred, adjusted with premiums in some cases, are used for transfer pricing purposes.

02.A.2 Assess the strengths and weaknesses of each approach; including how it corresponds to recognised best practice; how it compares to assumptions used for internal management information; and how it meets HMRC requirements.

Wholesale energy market prices constitute a potential comparable uncontrolled price, the appropriate application of which would be likely to meet the measure of 'best practice' set out in the OECD's Transfer Pricing Guidelines.

To be fully appropriate and robust, however, a high degree of comparability with both the individual transaction and the allocation of functions, assets and risks in the business model is required. We have observed that:

- The use of market price as a basis to measure the sale of output (or capacity) by generation businesses does not match the Key Performance Indicators (KPIs) given to generation management which focus on plant efficiency
- Where the market is illiquid, data is insufficient, and/or the parties trading have different characteristics from those observed in the market, the market prices must be adjusted to be appropriate and this is what many groups do. If extensive adjustment is required, it becomes harder to demonstrate comparability and transfer pricing risk may increase
- In some cases, options over generation capabilities are transferred. This is inherently more complex than drawing comparable prices directly from the market, involving adjustment to and modelling of market data. As a result this is dependent on implementation and is not transparent. While this approach to setting prices may be considered sound from a transfer pricing perspective, the economic models and prices that result would be difficult to test. It may be prudent to test the impact of these pricing policies, however, and the most practical way to achieve this would be to review the generation and trading divisions over time to confirm that they behave as expected; including where possible comparison between groups
- Rigid hedging policies imposing volume and timing requirements on generation and supply businesses may move the potential for profit around a group: for example requiring generation to hedge earlier than supply. If there are any expected shapes to pricing and demand curves, these could be used to leave an expected profit or loss in a trading arm, which is not currently reported in the CSS
- Risk premiums charged by trading companies could have the effect of moving risk, or duplicating a trading operation's reward for risk. However, amounts involved are limited.

02. EXECUTIVE SUMMARY
A. Transfer pricing

02.A.3 Assess how companies deal with moderate liquidity along the curve, lack of market prices around shape, and the use of internal trades. To what extent are the resultant prices fully market-based?

Groups' use of market prices as a basis for transfer pricing places reliance on liquidity and sufficient market data. This is either managed or brokered by the trading arm in accordance with group policies.

- As noted above, timing differences in hedging policy may seek to manage profits and losses arising in the trading operations
- Anticipated generation volumes are predominantly hedged with markets or a central trading body rather than being matched against expected demand from the group's supply division.
  - This approach is intended to result in the most efficient / profitable positions being taken and thus might be considered good for the consumer
  - Vertical integration does not create any barrier between wholesale market prices and supply divisions
  - Trading costs and volatility might be higher under the current model than if a less open and market based approach were used
- As market data and liquidity improve, trading functions often actively manage hedge positions; meaning traded volumes are high compared to total generation and supply. Hedging decisions, whether at the day-to-day discretion of generation/supply divisions or based on more rigid group policies, require a view of markets to be taken and can be profitable or unprofitable. It is not clear whether constant amendments to hedged positions as opposed to, say, a one-off position based on netting predictable demand with supply, creates risk or cost benefit.

02.A.4 Assess whether companies face any incentives to take profits in one segment rather than another for tax minimisation reasons. Is there any evidence that this is distorting transfer pricing methodologies and reported profitability?

We have found no evidence of any incentives for tax minimisation, nor any evidence of other intentional distortion.

02.A.5 Identify possible changes to current transfer pricing reporting practices which could be helpful in improving the CSS.

We have identified four potential changes to the CSS:

- Uniform treatment of free allowances
- Consistency of fuel costs in generation businesses
- Inclusion of the trading division in reporting
- Implementing a notional adjustment to reflect a single business model

In practice, the last two changes in particular may be difficult to achieve, depending on the level of detail required. However further recommendations regarding the transfer pricing issues identified are included in Section 3.

To increase confidence in the CSS, the use of wholesale market prices as a basis for transfer pricing policies might be tested to ensure that it does not distort reporting or pricing decisions.

02. EXECUTIVE SUMMARY
B. Accounting for longer term hedges and derivative contracts

02.B.1 Describe the methodology used by each firm to account for long term hedges and derivative contracts in the CSS, including the estimation and allocation of mark-to-market profits and losses.

Five of the entities account for financial instruments in their audited financial statements in accordance with IAS 39 and complying with the own use exemptions and hedging exemptions therein. These firms have correctly excluded the fair value effect of these financial instruments in their CSS.

One of the entities accounts for financial instruments in its audited financial statements in accordance with UK GAAP and is not required to adopt FRS 26 (UK equivalent of IAS 39) and accounts for these financial instruments on an historical cost basis. Therefore, no adjustment is required to exclude the fair value of these financial instruments in its CSS.

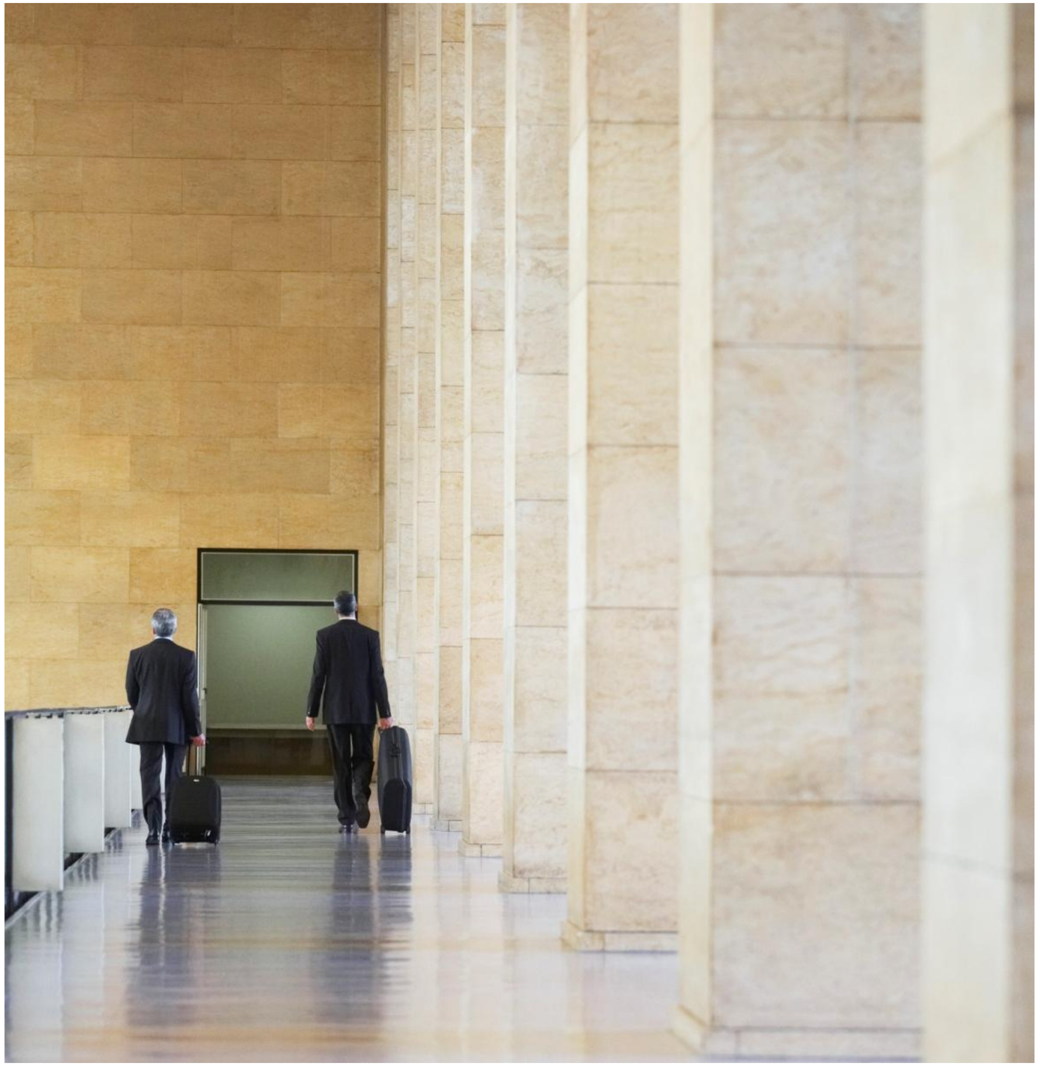
02.B.2 Assess whether it is practicable and beneficial to devise a common approach for estimating and/or allocating such profits and losses for the purposes of the CSS.

In complying with IFRS or UK GAAP a common approach for the treatment of financial instruments has been established.

Whilst we have not reviewed the fair value techniques adopted by the entities, comfort may be taken by the fact that the fair value techniques would have been audited by each entity's external auditor at each year end for the purpose of ensuring that the audited financial statements gave a true and fair view. This would also include the evaluation of hedging treatment and own use exemption, together with how embedded derivatives are identified. The descriptions given in the audited financial statements of each entity are in accordance with IFRS or UK GAAP.

02.B.3 Summarise any recommendations regarding hedge accounting arising from this analysis.

Whilst a more detailed review of the valuation techniques by an independent firm may highlight some inconsistencies between the valuation techniques and hedging strategies amongst the Big Six, as these fair value adjustments have been excluded from the CSS, the ability of each entity's hedge accounting treatment to affect the CSS is limited.



02. EXECUTIVE SUMMARY
C. Energy trading

02.C.1 Describe the extent to which trading activity is included within the CSS.

Any speculative energy trading activities of the Big Six have been excluded from the CSS, mainly due to the way that each company structures its business model.

There are costs and charges relating to other trading activities such as hedging that are included within the CSS, for example as indirect costs, as part of power and fuel costs or as a reduction in generation income. Corresponding costs and profits/losses may fall in parts of the groups outside the CSS. To this end we refer to the comparisons in relation to trading activity within the main body of this report.

02.C.2 Describe how firms distinguish between speculative trading and transactions undertaken for hedging purposes; and how this distinction is reflected in the CSS.

Speculative trading represent a very small element of the overall results currently shown in the CSS, as these figures are not considered material to the financial statements (or CSS). This is based on our evaluation and analysis of the disclosures within the financial statements (and CSS) of the Big Six and the trading which is undertaken not for hedging but for speculative purposes.

'Speculative' trading is defined for the purposes of this report as the taking of a market position in pursuit of profit from the trades themselves rather than the management of cost-effective supply for customers.

The energy businesses have group policies regarding hedging, which generally include specifying a time in advance of delivery by which the position should be hedged. Normally this is different for generation selling power into the market and supply drawing requirements out. Generation tends to hedge its output, capability and capacity earlier than the supply business will hedge its requirements. Due to the volatile nature of the market, hedging is utilised as a means of managing risk.

02.C.3 Describe how the companies allocate specific trades, especially those required within short term time horizons and within the Balancing Mechanism to balance the company's overall GB position. How are the costs of such trades allocated across Generation, Supply or Trading? What is the rationale for these allocation rules?

Transmission costs associated with both generation and the balancing mechanism are by and large recorded within the generation division of the GB accounts. However, the allocations of costs of such trades across the business are dependent on a variety of factors and the type of Transfer Pricing model employed.

02.C.4 Assess the implications of international business models and the extent to which they impact on reported CSS treatments.

An effective transfer pricing policy must appropriately reflect the business model used, as this will dictate how the functions, assets and risks of operations are divided between the divisions or companies in question.

Most groups follow a broadly similar business model with a single body trading with the markets, through which the generation divisions sell power or capabilities and from which the supply segments acquire power and gas. However, within this model there are significant differences in how functions are located between divisions and how they interact.

The main variations are:

- Some generation divisions sell either their production capacity at fixed rates, or use a complex system of options over production to hedge their output
  - this gives a return to the generation division that is independent of the electricity volumes actually produced
  - the trading body, or supply segment, receives the benefit or cost of market movements
- In other cases the central trading body acts more like a broker, standing between the generation and supply segments and the wholesale markets/counterparties

02. EXECUTIVE SUMMARY
C. Energy trading

02.C.5 Assess whether financial transparency requires additional information disclosure relating to energy trading activity.

Given that currently trading entities/divisions represent a ‘missing link’ between the generation segment and the WACOE/WACOG shown in the supply segments, an option to increase transparency may be to require the results of trading divisions to be included.

There are two ways in which the inclusion of trading divisions could be achieved:

- Basic inclusion – For the big six the majority of trading divisions are contained within a UK legal entity that undertakes no other activity, or are within a UK branch of an equivalent entity. Including the total GB figures for trading, including speculative trading activities, might therefore be relatively straightforward, although for two of the groups a greater degree of analysis is likely to be required than the others.
- Detailed inclusion – speculative trading does not form a part of the standard power and gas supply chain, yet the figures arising from it could easily mask the results of other functions of the trading entities. It is likely to be possible for each entity to identify which trades have been undertaken for speculative purposes and what has been done for other reasons, such as acting as a central broker or purchasing capability options and managing scheduling.

The ‘detailed inclusion’ option would allow for the inclusion of a wider range of activities to be presented in the CSS for each group that would capture all charges and profits paid to central trading bodies as well as associated costs for those trading entities. This should improve the confidence in the figures being provided by the Big Six; however it would be difficult and costly for at least some groups. In particular, the licensed entities in the UK would have no legal powers to require other group members to provide the necessary information.

A basic inclusion of all trading activity data is a halfway-house and could provide some comfort that profits are not being distorted in favour of trading entities, however the inclusion of speculative results is likely to reduce its usefulness and potentially to be confusing to readers of the CSS who would not be able to differentiate between speculative trading results and energy supply chain data.

Continuing without including trading results in the CSS is plausible and has least cost; however this retains current limits to the transparency of the statements with the concern that there is potential for it to appear that there could be ‘missing profits’ in the unreported areas.

This is discussed further in recommendation R.4.

02.C.6 Summarise any recommendations regarding the reporting of energy trading arising from this analysis.

Without exception, trading activities within the Big Six are closely aligned to either the transfer pricing or hedging policies, therefore, any recommendation in regard to energy trading is covered within our transfer pricing or hedging recommendations.

02. EXECUTIVE SUMMARY
D. Treatment of exceptionals

02.D.1 Describe the treatment of exceptional items (unless already covered in sections A,B or C).

In preparing the CSS the entities have presented a number of reconciling items. Some of these are termed exceptional items.

In UK GAAP, where the concept exists, it only relates to items which need to be separately disclosed because of their size or incidence if the financial statements are to show a true and fair view. Therefore, the term, where it is used, is used as a means of emphasising an item included in the measurement of profit.

In the CSS this is being used in a different way. In effect it is being used by some companies to describe items which have been excluded from the CSS.

Within the Big Six, half of the companies do not explicitly refer to the term 'exceptional' within their CSS whereas the remaining companies do use the term 'exceptional'.

In general these are a small number of the total reconciling items. The overall number and type of reconciling items is largely dependent upon the basis of GAAP adopted and the audited documentation to which the CSS is reconciled. As there is little or no similarity of these factors, the number and type of reconciling items varies significantly.

For example, in preparing statutory accounts, some of the firms analyse exceptional items into a separate column in their income statement, thus meaning that when they come to prepare the reconciliation these exceptional items do not need to be adjusted for.

Furthermore, the entities have all chosen to reconcile a variety of different line items on the CSS, with differences between whether EBIT, EBITDA and/or revenue are reconciled to statutory information.

In addition reconciling items arise to adjust the numbers from the financial statements to meet the requirements of the CSS eg. to exclude unlicensed activities. Other adjustments are to exclude items not considered appropriate by the companies for example one off write downs.

In reviewing the exceptional items and reconciling items, we also noted inconsistencies on how the results of Joint Ventures and Associates are included within the CSS.

02.D.2 Assess whether it is practicable and beneficial to devise a common approach to these items for the purposes of the CSS.

In order to do this it would be necessary to:

- Determine a common starting point e.g. revenue, costs and EBITDA
- Distinguish those items which are necessary to draw up the CSS
- Determine the purpose of the statements e.g. to show on-going profits and what adjustments are needed to show this

In preparing the CSS, the Relevant Licensee should account for Joint Ventures and Associates (which hold a generation or supply licence relating to the generation or supply of gas or electricity in the UK) as follows:

- The share of revenues, of Joint Ventures and Associates to be included within revenue;
- The share of the profit before tax of Joint Ventures and Associates to be included with EBIT and EBITDA; and
- The share of the generation volumes of Joint Ventures and Associates to be included within the generation volumes.

For each of the items, the Relevant Licensee's share of the income and expenses of a joint venture or associate should be combined line by line with similar items in the Relevant Licensee's CSS or reported as separate line items in the Relevant Licensee's CSS.

Associate

An Associate is an entity, including an unincorporated entity such as a partnership, over which the Relevant Licensee has significant influence and that is neither a subsidiary nor an interest in a joint venture.

Joint Ventures

A Joint Venture is a contractual arrangement whereby the Relevant Licensees and one or more parties undertake an economic activity that is subject to joint control.

02. EXECUTIVE SUMMARY
D. Treatment of exceptionals

02.D.3 Summarise any recommendations arising from this analysis.

In order to achieve more uniformity of statements we would ask you to consider the following:

- Define Revenue and EBITDA pre any exceptional column as the starting point of the reconciliation
- All reconcile to an audited IFRS income statement* (or set of statements)
- Divide reconciliation into items adjusted to ensure that statements relate to generation or supply
- Develop principles for other items to be excluded
- Review by independent auditor of all statements to ensure comparability
- Issue further guidance as above on the treatment of Joint Ventures and Associates within the CSS.

In developing principles for other items to be excluded, we would also suggest that only a limited number of items are allowed to be excluded. Although more work needs to be carried out on this, we would suggest:

- Mark to market adjustments;
- Restructuring costs which been disclosed as such in the original financial statements; and
- Items relating to disposals.

We would not include asset write downs as they would not be reconciling items to EBITDA.

** An IFRS Income Statement is in this instance is an Income Statement present in the statutory accounts of the group or relevant company prepared under International Financial Reporting Standards.*

In determining a common starting point for the reconciliation, we believe that the existing format adopted by one of the companies provides the most clarity and transparency on the reconciling items. We would suggest that guidance should be issued stating:

In reconciling the CSS to audited financial information, the reconciliation should adopt a columnar approach ensuring that each line item in the CSS (revenue, other revenue, direct fuel costs, other direct costs, indirect costs, EBIT, EBITDA and volume is reconciled to audited financial information. Narrative should be included for each reconciling column to enable the user of the CSS to understand the nature of the reconciling item.

	Per CSS	Reconciling item 1	Reconciling item 2	Reconciling item 3	Per audited financial information
Revenue	xxx	xxx	xxx	xxx	xxx
Other revenue	xxx	xxx	xxx	xxx	xxx
Direct fuel costs	xxx	xxx	xxx	xxx	xxx
Other direct costs	xxx	xxx	xxx	xxx	xxx
Indirect costs	xxx	xxx	xxx	xxx	xxx
EBITDA	xxx	xxx	xxx	xxx	xxx
Depreciation and amortisation charge	xxx	xxx	xxx	xxx	xxx
EBIT	xxx	xxx	xxx	xxx	xxx
Volume	xxx	xxx	xxx	xxx	xxx

03. SUMMARY OF RECOMMENDATIONS

03. SUMMARY OF RECOMMENDATIONS
Overview

Overview

Over the following pages we have provided details of our recommendations with regards to the recommended changes to the company reporting guidelines, and in some cases additional supporting actions that will support the goal of improved usefulness of the CSS and transparency and comparability of results.

For each recommendation we have included an analysis of the expected benefits and the potential cost and risks of the changes.

In summary, the key changes that we are recommending include:

R1. Require the Big Six to publish their CSS at the same time and to the same year-end

R2. Appoint an independent auditor to provide an opinion on the statements each year

R3. Instruct the Big Six to reconcile their CSS to an audited IFRS Income Statement

R4. Require the reporting of trading functions' results, including disclosure of the risk each trading function assumes

R5. Test that the use of wholesale market prices as a basis for transfer pricing policies does not distort reporting or pricing decisions

R6. Introduce a uniform reporting treatment for common recurring items in the CSS, in particular free allowances and fuel costs

R7. OFGEM to provide more detailed guidance on the scope and definition of exceptional items

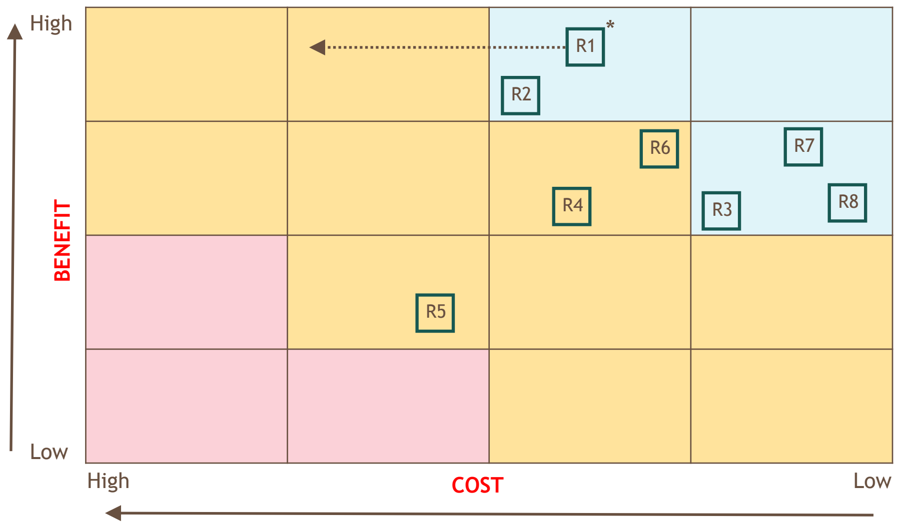
R8. OFGEM to instruct the Big Six to reconcile the CSS to the same starting point

Axis

The diagram below details our overview and perspective of the feasibility and desirability of each of the recommendations identified on the previous pages.

The 'Benefit Axis' refers to the expected benefits gained by implementing the recommendation as part of the revised guidelines for the CSS.

The 'Cost Axis' refers to the expected costs and barriers to implementation.



* For SSE the cost of implementation of this recommendation is significantly higher.

03. RECOMMENDATIONS FOR IMPROVEMENT

Expected benefits, costs, and risks of changes

OVERVIEW	KEY BENEFITS	KEY COSTS/BARRIERS
R1. Require the Big Six to publish their CSS at the same time and to the same year-end		
OFGEM should seek to impose a reporting deadline on the Big Six, to ensure that all CSS are produced at the same time, and set against co-terminus year ends to ensure that comparison across the firms is made easier.	The main benefit would be increasing comparability across the Big Six. BDO considered the impact of imposing a new reporting schedule on companies and any impact that it would have on investor confidence and information and management of expectations. At present, five of the six companies operate to the same year end, therefore the only impact that imposing co-terminus year ends would be to require the final company to either produce a separate statement at the year end, or provide a reconciliation to the CSS to enable comparison to be made across the firms. The benefits of this improvement recommendation would be: • Comparison between all six companies will be improved due to the results being for the same reporting periods and thus set against similar and comparable cost bases i.e. gas price fluctuations etc • Providing the statements to OFGEM at the same time would allow OFGEM the opportunity to quickly review the CSS submissions against one another and thus qualify any queries or concerns quickly • If aligned with a company's year end and annual reporting cycle, the companies could also modify the terms of engagement with their external auditors to help support the creation of the CSS.	The key significant barrier to imposing the same reporting deadline across the Big Six will be the extra burden that this would place on the company that does not have a common year end with its peers. In this case the company would be required to generate interim statements or reports that would allow for a useful and comparable reconciliation to be performed. There would be several ways of achieving co-terminus dates, all of which would have a cost for the company currently on a different reporting cycle. These are: • Changing the statutory reporting year end – this would impose a high cost and these are possibly other intangible reasons why this would be problematic, such as investor relations; • Prepare an interim statement at 31 December – this would impose less cost than changing the year end but it would not be audited, although this could be reviewed to the level that the half yearly financial results announcement is reviewed; and • Request that the company that reports to a different year end has an additional full audit for its results to 31 December – this would impose prohibitive costs on this company of up to £1m. Another way of achieving comparability and reducing the burden on finance teams during their busiest period would be to consider moving the reporting period to 30 June. If the reporting period for the CSS for all entities was changed to 30 June, then there would be no audited information to reconcile the statement to. However, for some of the entities, there would be a publicly available interim financial report to 30 June, but this would not be audited (although will have been reviewed by the auditors). A move to a 30 June reporting period could be considered in conjunction with R2 - Appoint an independent auditor to provide an opinion on the statements each year.

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

OVERVIEW	KEY BENEFITS	KEY COSTS/BARRIERS
R2. Appoint an independent auditor to provide an opinion on the statements each year		
OFGEM should seek to implement an independent review of the CSS prior to their publication. Each company would have the opportunity to provide their statements to independent auditors with specific accounting expertise to provide comment on the completeness and accuracy of the CSS and also to provide high level commentary on key movements and comparisons between the firms.	Improved transparency will be achieved through continuous improvement and education. Through an independent review and opinion there can be incremental improvements over the long term through comparison, recommendations, review and assessment. We consider the key benefits of appointing independent experts to provide an opinion on the CSS are: • The ability to offer expert advice from a position of independence that is not clouded by existing relationships with any of the companies • Provide commentary on the results disclosed by the companies in the context of wider market conditions and external factors that may have influenced this eg volatility in fuel prices, natural disasters, weather conditions, hedging policies, new entrants to the market, changes in accounting policy or acquisitions/disposals • Providing assurance to the key stakeholders that the statements are accurate, complete and a fair reflection of the performance of each of the firms • Provide feedback and commentary with regard to recommendations for best practices, based on the auditors' broad experience and expertise gathered from audits in various industries, not exclusively limited to the energy sector	The key cost and barriers for providing the independent review are: • Determining who would be required to pay the fees of the auditors, if one firm is used across the board and the work is not included as an extension to the existing external auditors responsibilities • Ensuring that the scope of the review is sufficient to ensure that a useful and binding opinion can be reached • The key barrier would be the extent to which the firms would be willing to enable an additional company access to their confidential data in order to provide a detailed analysis of the CSS

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

<table>
<tr><th>OVERVIEW</th><th>KEY BENEFITS</th><th>KEY COSTS/BARRIERS</th></tr>
<tr><td colspan="3">R3. Instruct the Big Six to reconcile their CSS to an audited IFRS Income Statement.</td></tr>
<tr><td>OFGEM should seek to ensure that the CSS are all starting from the same point of reference, in this case audited IFRS Income Statements.</td><td>The main benefit would be increasing comparability across the Big Six.

This will allow greater comparability of statements and allow for an easier assessment of reconciling items between the IFRS Income Statement and the CSS.

This would also reduce the number of cases where one company has to include an item in its reconciling statement whilst another has already excluded the same item at arriving at its starting point.</td><td>There would be costs for a number of the companies who currently reconcile to the segmental accounting note in their financial statements. This cost effect would be aggravated for those companies without a UK parent and who currently reconcile to a European consolidated statement. A problem here is that this would add extra lines to their reconciliations and make the disclosures more complex. To partially offset this each entity could prepare a consolidation to the highest UK parent company level. These companies exist in most of the group structures but no consolidation is carried out as there is a Companies Act exemption of which they take advantage.

An alternative would be to require each entity to reconcile the CSS to each UK company within the group which conducts licensed activities. This is the existing approach taken by two of the energy companies, although one of these aggregates these companies within its CSS.

One energy company’s CSS already provides a highly informative reconciliation, as it reconciles not only EBIT or EBITDA but also each line item on the CSS to statutory accounts. The cost of reconciling to individual financial statement should not be prohibitive. The barriers are that:
• It would add another layer of complexity for the larger groups;
• More divisionalised entities would find this approach difficult.</td></tr>
</table>

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

<table>
<tr><th>OVERVIEW</th><th>KEY BENEFITS</th><th>KEY COSTS/BARRIERS</th></tr>
<tr><td colspan="3">R4. Require the reporting of trading functions’ results, including disclosure of the risk each trading function assumes</td></tr>
<tr><td rowspan="2">OFGEM should require the reporting of results for energy companies’ trading functions, including the risk each trading function assumes in the supply chain.

There are two options with differing levels of cost and benefit - (A) including overall figures for trading divisions; and (B) detailed analysis to ‘non-speculative’ results.

If the costs and barriers can be overcome and tolerated, we would recommend the detailed analysis option (B).

If desired, these options could be combined through the basic inclusion of all relevant data (A) which is then analysed in detail (B).</td><td>Option A – basic inclusion

Including the complete P&L details for trading operations will present a picture of each group’s total UK operations, missing only ancillary services.

Implementing this allows:
• Greater visibility of profit across the whole supply chain, including scheduling and acquiring generation options
• Potential to reduce concern about profits being diverted or disguised

Compared with Option B below, the data should be relatively easily available due to UK trading activities taking place in distinct entities or UK branches of overseas entities. There is one exception to this as all trading activities take place outside the UK.</td><td>The key costs and barriers for reporting trading results under Option A – basic inclusion are:
• There are a variety of trading function models used by the Big Six; without requiring the same business model to be adopted comparability between groups will not be improved, only transparency of results
• Speculative trading activities are not part of the energy supply chain, being something that unrelated businesses such as merchant banks can engage in, and their inclusion in the results would significantly reduce clarity of energy supply chain elements
• The licensed UK entities of the Big Six have no legal authority to require other group members to provide profit and loss details (subject to their contractual arrangements); requiring the licensed entities to provide this information might therefore rely on goodwill and/or shareholder intervention
• One of the energy companies would need to undertake comparatively detailed analysis to split out the activities of its trading body that relate to the UK market</td></tr>
<tr><td>Option B – detailed inclusion

Separating out the speculative trading activities to show only P&L details of other activities such as broking, acquiring generation options and/or managing scheduling would allow a clearer and more complete picture of activities undertaken in the energy supply chain.

In particular this would allow:
• An understanding of the transfer of risk and profits between entities where functions are shared, such as the toll generation models
• A clearer picture of the effects of timing of hedging and transfers within the groups, such as whether there is likely to be a predisposition towards trading functions profiting and whether this has any impact on the supply divisions
• A reduction in concern about profits being diverted or disguised without confusion caused by significant and variable speculative trading results</td><td>The key costs and barriers for reporting trading results under Option B – detailed inclusion are:
• As above, the licensed UK entities have no legal basis to require other group members to provide them with details
• Most groups would need to undertake detailed analysis, however if speculative portfolios are recorded separately this should still be possible
• A clear definition of trading (as opposed to speculative trading) will be required from the Regulator; this is likely to be a qualitative rather than quantitative measure that could be difficult to substantiate

These options will give rise to a cost to all businesses in the industry; for some energy companies this could be high. The method, impact and benefits may be determined in advance through a modelling exercise undertaken by the Regulator</td></tr>
</table>

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

OVERVIEW	KEY BENEFITS	KEY COSTS/BARRIERS
R5. Test that the use of wholesale market prices as a basis for transfer pricing policies does not distort reporting or pricing decisions		
OFGEM should test that the use of wholesale market price as the main transfer pricing measure does not have a distorting effect on reporting or pricing decisions	The wholesale market price is used by most energy companies as the basis for their transfer pricing policy, although in many cases this is subject to adjustment. This type of comparable can be appropriate (even recommended) for transfer pricing purposes provided it is correctly applied. Testing the current policies, for example against the cost of generation, would allow: • More confidence in reporting based on these transfer pricing policies • Further insight into the impacts and role of groups' hedging strategies • More effective comparison of the performance of generation businesses	The key costs and barriers to analysing the effectiveness of using wholesale market prices for transfer pricing are: • A view of the effectiveness of the market will be required, especially at lower levels of liquidity (eg is the market made only by the tested parties at any point?) • A definition of alternative measures will be needed, for example should the cost base include provision for future refurbishment or fuel costs, and on what basis? The cost to businesses from this will be limited compared to recommendations R4 and R6 (so far as it relates to fuel costs); they are also likely to be one-off costs. These are likely to fall with the Regulator to ensure visibility across the tested businesses.

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

OVERVIEW	KEY BENEFITS	KEY COSTS/BARRIERS
R6. Introduce a uniform reporting treatment for common recurring items in the CSS, in particular free allowances and fuel costs		

OFGEM should introduce a uniform treatment of common items, in particular free allowances and fuel costs, which are currently treated inconsistently and so create distortions.	Agreeing a uniform treatment for disclosure of certain key items would allow both consistency and transparency of reporting. To the extent these allocations are addressed under transfer pricing policies, this will also add beneficial clarity and aid comparability of statements:
	• Free allowances – currently most groups allow the benefit of allocations under the NAP to impact their CSS figures while others add the benefit in. Currently these are not allocated under the same segments.
	    • Removing all benefit from free allowances (including a cost at approximate market value where relevant) as one of the companies has done would give greatest uniformity but require most work; this would also allow most consistency with reporting from 2013 when free allowances cease and with new generators in the market who did not receive free allowances
	    • A more practical solution is to instruct companies not to add in a market cost, thus reducing its generation cost; however this will give less consistency either between the Big Six, as they calculate amounts differently, or future periods and new entrants
	• Fuel costs – again, the treatment of this varies, both regarding what segment of the CSS they fall in and how they are calculated.
		The extent of the change required for businesses will vary based on the similarity of their current models to the preferred model that is determined and selected. While it will depend in the method, this cost could be comparatively high for one of the companies in particular and would rely either on detailed information and analysis by their trading entity or estimates.
		The lifetime of the benefit from common treatment of free allowances is limited as they expire at the end of 2012.
		Costs to other businesses are expected to be limited, especially as it is understood that the relevant information should be easily obtainable. There may be additional up-front cost to the Regulator from defining the standard to be met.

03. RECOMMENDATIONS FOR IMPROVEMENT
Expected benefits, costs, and risks of changes

OVERVIEW	KEY BENEFITS	KEY COSTS/BARRIERS
R7. OFGEM to provide more detailed guidance on the scope and definition of exceptional items		
OFGEM should update the guidelines for the CSS to include instructions on the definition and treatment of exceptional items.	The main benefit would be increasing comparability across the Big Six. This would ensure statements are drawn up in consistent manner and are thus more comparable. Also by establishing the principles which apply to 'discretionary' reconciling items it will increase the information value of the CSS. If a more standardised method of preparation is established under R3 above, this will also make reconciling items comparable, as the starting and end point would be the same for all entities. This would enable reconciling items to be better analysed into reconciling items required by the license condition (e.g. non-licensed activities excluded) and exceptional items. The requirements should also state that any exceptional items are clearly labelled within the CSS together with an explanation of why they have been excluded. We would also suggest that only a limited number of items are allowed to be excluded. We would suggest: • Mark to market adjustments; • Restructuring costs which been disclosed as such in the original financial statements; and • Items relating to disposals or major plant disposals.	Further guidance could be issued on the treatment of exceptional items. This should take into account the points in R3 to ensure that there is a common starting point together with further guidance on the transparency of restructuring costs, disposals of business segments and fair value adjustments. For each of the entities, the cost of complying with additional guidance would be minimal as this is really just an extension on the existing disclosures given with the CSS. There would be no barriers to each of the entities complying with additional guidance.
R8. OFGEM to instruct the Big Six to reconcile the CSS to the same starting point		
OFGEM should define Revenue, Cost and EBITDA pre any exceptional column as the starting point of the reconciliation. This guidance should also deal with associated companies and joint ventures.	The main benefit would be increasing comparability across the Big Six. This will ensure a common starting point and it is what the majority of companies do anyway. In determining a common starting point for the reconciliation, we believe that the format adopted by one of the companies provides the most clarity and transparency on the reconciling items. We would suggest that guidance should be issued stating: "In reconciling the CSS to audited financial information, the reconciliation should adopt a columnar approach ensuring that each line item in the CSS (revenue, other revenue, direct fuel costs, other direct costs, indirect costs, EBITDA, EBIT and volume is reconciled to audited financial information, or other published information in the case of volume. Narrative should be included for each reconciling column to enable the user of the CSS to understand the nature of the reconciling item."	This would require change by companies which don't, and thus require additional work from their finance teams to comply with OFGEM's requirements. The cost should however be fairly minimal particularly if R3 is introduced.

APPENDIX A – SUMMARY OF ANALYSIS

APPENDIX A.1 – TRANSFER PRICING COMPARISON

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Transfer pricing overview

Overview

The majority of countries, including the UK, incorporate transfer pricing provisions in their tax legislation. In most cases these are based on the framework provided by the OECD in their Guidelines on Transfer Pricing for Multinational Enterprises and Tax Authorities ('the Guidelines'), although it is often the case that each territory adapts these Guidelines on implementation.

In overview, transfer pricing regulations seek to ensure that transactions between different parts of a business are conducted in the way independent parties would address the same arrangements, which includes using rates these parties would agree. The result is that the transactions between connected parties must be on an arm's length basis.

The primary focus of transfer pricing is on transactions between parts of multinational enterprises in different territories, as in these cases there is considered to be an opportunity for the business to structure its pricing policy to locate income and resulting taxable profits in the territory with the lower tax rate, thereby reducing tax costs. Many territories, including the UK, also require arm's length transfer pricing requirements to be used in transactions between a Group's companies within that country.

Transfer pricing is increasingly relevant, both as multinational enterprises are now more commonplace and because companies structure their business models to best support their operational requirements. In practice, this means that rather than duplicating a standalone company's functions and activities in full in each territory, businesses structure their value chain to maximise specialisation and minimise costs arising from duplication. The resulting functions, together with the assets they employ and risks they assume, must be priced at arm's length rates when either transact with or provide benefit to other entities in a group.

Principles

To determine an arm's length price, key questions must be addressed. While the Guidelines provides extensive commentary which is supplemented by the experience of their practical application, these questions may be summarised:

- Would independent parties enter into this transaction or arrangement?
- What terms would they apply to the transaction?
- How should it be priced, and how might this pricing be determined and supported?
- How is the policy implemented? Does this appropriately reflect the intentions of the pricing policy?

Essentially, these pricing arrangements should reflect the substance of the activities of the parties involved – its functions, its assets and the risks it assumes.

Consideration of transfer pricing in this study

A typical transfer pricing review approaches the issue from a tax perspective, asking whether the requirements of tax legislation have been met based on a detailed analysis of the facts and circumstances of the arrangements in question.

In the course of this project, we have carried out a high-level review that seeks to understand and explain the ways in which the different business areas of each group interact and how pricing policy is structured. We have applied similar principles that would apply in a tax review of transfer pricing policy, but stopping short of seeking to assess whether specific prices are truly reflective of arm's length terms.

We have relied on statements and responses of the Big Six and have not sought to independently validate these.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Transfer pricing methodology

Business models

To be effective a transfer pricing policy must appropriately reflect the business model used, as this will dictate how the functions, assets and risks of operations are divided between the divisions or companies in question.

In overview, the activities of the Big Six are generally divided between:

- **Generation** – power production activities, including the management and maintenance of the production assets
- **Trading** – a function to manage activities such as hedging and interaction with the wholesale power market on behalf of other parts of the group
- **Supply** – winning and retaining domestic and commercial customers, with responsibility for price setting, customer interface and power supply to meet demand

These divisions are found in each the Big Six other than in SSE. There are, however, varying allocations of functions between divisions within different groups and in how these divisions interact. All businesses reflect the focus on respective functions in their strategy and the key performance indicators of the management of each division.

Generation

In respect of generation, there are several common sets of functions that are undertaken within groups with some variation in whether this is within the generation division or the trading division, and how these divisions interact.

The key elements are:

- Physical ownership, maintenance and running of power stations
- Scheduling plant run times based on market conditions (including capacity/capability purchased under PPAs)
- Determining when and how to hedge positions

The models operated by the Big Six in respect of generation fall broadly into two categories:

Central broker model

Several groups operate with all activities linked with generation contained in their generation divisions, using central trading bodies as an internal market or route to market. In some cases requests for trades from the generation division are netted off before being given to the central broker.

This model should result in a generation division that is broadly similar to one directly facing the markets. The way it is applied by Scottish Power varies slightly from this model by having forecasting and scheduling centralised in its trading division.

Toll/capacity based generation model

The alternative approach is to separate off the key responsibilities of the generation business to create a division that focuses on maintaining efficient and flexible plant and is relatively detached from the markets. The KPIs of generation’s management are set with these aims in mind.

SSE achieves this through selling generation capacity from its generation division at a contracted rate in a similar manner used for some PPAs with independent and joint venture partners (considered in more detail on slide 31). Whilst there is scope to renegotiate rates, the generation business is largely ambivalent to market conditions and scheduling.

E.ON and RWE npower follow an option based approach with potential generation capability sold in advance based on an intrinsic value (current market spark or dark spreads) and an extrinsic value (the potential increase in value due to market changes over the life of the option). RWE npower handles this in a manner closer towards the central broker model with the generation business still able to benefit from the prompt and balancing markets.

Supply

There is more consistency in the supply model. Due to its notional divisionalisation, the impact of various procurement, scheduling and trading activities feed directly through into the WACOE and WACOG for SSE’s supply segment. For all other groups, the supply divisions are treated as purchasing power and gas from or through a central broker, generally based on prevailing market prices.

Description of models

The business models for each group and their impact on the CSS are summarised in the following slides. Further details are given in Appendix B.

APPENDIX A.1 – TRANSFER PRICING COMPARISON

Generation business models

Toll generation

Central broker model

COMPANY	GENERATION DIVISION (REPORTED)	TRADING DIVISION (NOT REPORTED)	SUMMARY
Scottish and Southern Energy	[redacted]	[redacted]	These groups have a dedicated energy trading entity (real or notional)* that handles all market activity (including fuel and allowances purchasing and energy sales) and plant scheduling. Renewable generation is treated differently (where included in statements). The generation role varies from purely managing capacity to having access to the balancing market.
E.ON	[redacted]	[redacted]	
RWE npower	[redacted]	[redacted]	
Scottish Power	[redacted]	[redacted]	These groups have a central energy trading entity but it is used as a broker / route to market rather than seeking to transfer risk.
EDF Energy	[redacted]	[redacted]	
Centrica	[redacted]	[redacted]	

CONTENTS REDACTED

* SSE does not have distinct trading and supply segments, therefore it separates its business notionally for the CSS

Table A.I.1 – Generation business models comparison

APPENDIX A.1 – TRANSFER PRICING COMPARISON

Supply business models

COMPANY	TRADING DIVISION (NOT REPORTED)	SUPPLY DIVISION (REPORTED)	SUMMARY
Scottish and Southern Energy	[redacted]	[redacted]	SSE does not have a full separate trading division. A comparatively large range of generation/ sourcing functions sit within the notional 'trading' segment.
E.ON	[redacted]	[redacted]	Most groups appear to operate broadly similar models for their retail divisions; buying supplies in advance (from three years to 18 months depending on group) based on market prices/cost. Other than entering hedging transactions, trading divisions do not in general limit the exposure of supply divisions.
RWE npower	[redacted]	[redacted]	
ScottishPower	[redacted]	[redacted]	
EDF Energy	[redacted]		
Centrica	[redacted]		

CONTENTS REDACTED

Table A.1.2 – Supply business models comparison

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Summary of impact on CSS

	GENERATION, SCHEDULING, FUEL AND ALLOWANCES				
	Asset ownership/ 'base' generation	Scheduling/benefit of short-term changes	Constraint payments	Benefit of NAP allowances	Impact of long-term fixed price contracts
Centrica	Run as full generation business, including cost of fuel and allowances				Long-term contracts have regular price reviews
EDF Energy	Run as full generation business, including cost of fuel and allowances – seek to minimise exposure to focus on asset management				No beneficial / onerous contracts
E.ON	Receives capacity payments (based on market pricing at time of transfer, inc. extrinsic)	All scheduling handled by EET, benefits of decisions to run/not run lie with EET		Sell free allowances at fixed price (market price + swap)	Contracts or effects of contracts transferred to EET as part of 2009 transfer
RWE npower	Receives capability payments – similar to a hedge of spark/dark spread + extrinsic. Don't show fuel / allowance costs	Once options are exercised, increases or decreases in production benefit generation division, changes before exercise do not		Sell free allowances	No beneficial / onerous contracts
ScottishPower	Run as full generation business, including cost of fuel and allowances – seek to minimise exposure to focus on asset management – optimisation etc managed by SPEML but impact to generation			Removed on the basis that they would not be available to new entrant (note 1(i) p4)	Beneficial gas contracts are fed through to retail
SSE	Receives capacity payments (fixed in short-term). Doesn't show fuel / allowance costs	Generation results (using capacity + PPAs etc) feed through to retail WACOE	Some constraint payments fall to trading segment – but as segment P&L targeted at nil, indirectly feeds to supply	Generation results (using capacity + PPAs etc) feed through to retail WACOE. Gas is allocated between generation and supply by volume, priced based on average cost	

Key: Generation segment; Retail segment; Other/Overseas; Not undertaken or N/A; Adjusted out

Table A.1.3 – Summary of impact on CSS comparison

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Strengths and weaknesses

Assess the strengths and weaknesses of each approach; including how it corresponds to recognised best practice; how it compares to assumptions used for internal management information; and how it meets HMRC requirements.

'Best practice' theory

The OECD's Guidelines seek to provide 'best practice' for setting and testing transfer pricing policy. For example, it sets out pricing methods which may be applied:

- **Comparable uncontrolled price ('CUP')** – a price for a transaction on similar terms either between the tested company and a third party, or between two third parties in the market; where available this is often viewed as the preferred approach
- **Resale minus** – where an appropriate gross margin is calculated and deducted from the selling price; this is often seen where a distributor buys products from a connected party for sale to its customers
- **Cost plus** – a mark up on cost is calculated as the sale price for a product or services; this is normally seen where the activity is strongly focused around effective management of a cost base (as opposed to sales), for example manufacturing or the provision of services
- **Profit split** – where transactions are highly interrelated and cannot be easily separated, for example where both parties own valuable intellectual property or both make valuable and unique contributions to the product or service
- **Transactional net margin method ('TNMM')** – a measure of the net profit relative to an appropriate base; this is often used when data for other methods is not available
- Other methods are permitted, although these are infrequently used

To the extent that transfer pricing policy selects the most appropriate method for the transaction – something that will be governed by the functions, assets and risks of the business – and applies an appropriate rate, the policy should be viewed as meeting the arm's length standard. If this is also documented in accordance with local tax authority requirement, a policy may be considered to be best practice.

Whilst the CUP method is preferred, it is often difficult to exactly match the terms and circumstances of intragroup transactions to those of the transactions identified between third parties. To this end, it is acceptable (and potentially required) to make adjustments to CUPs to account for functional differences. If too much adjustment is required, however, this greatly weakens the robustness of the comparable price used.

An example of this in practice would be to consider whether a trade between a trading and supply division is genuinely comparable to a price reported for a similar wholesale trade; this might take into account:

- The volume of a trade
- Whether the trading division should share the benefit of being able to offset the order against a matching order from the generation division
- Differences between several trades seen in the market

Application of 'best practice'

The transfer pricing policies applied by the Big Six to govern transactions between the generation, trading and supply activities are based either on the wholesale energy price – a potential CUP – or a cost-based arrangement in the case of the way SSE rewards its generation business. Both of these correspond to the Guidelines and may be viewed as reasonable to the extent they support their respective business models.

Over the course of the project we identified several areas worth questioning in more detail:

- A1.1 Whether the use of the wholesale market price is an appropriate comparable given the location of risk in the business model? (Recommendation 5)
- A1.2 Whether some businesses should charge a 'risk premium' from their trading division?
- A1.3 Whether speculative trading activities feed back profit or losses into the power supply chain? (Recommendation 4)
- A1.4 Whether the timing of hedging policies for generation and supply is consistent and appropriate? (Recommendation 4)

These areas and the strengths and weaknesses of the methods employed, are considered in this order in the following slides.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Transfer pricing methodology - focus on SSE

A1.1 - Transfer pricing method

The transfer pricing model operated by SSE is distinct from the other five businesses, in particular in how it rewards its generation business. SSE uses a fixed base for its payments to generation for its output. This amount is derived from SSE's dealings with generators where SSE is a joint venture partner and, as such, is effectively in a third party negotiating position.

By basing its pricing on that agreed with a party that has its own distinct commercial interests, this should be a supportable arm's length price – subject to having:

- Minimal differences in the bargaining power of the parties (e.g. if a small JV partner is effectively only providing finance then it might be content with a reward that a skilled market participant with a number of power stations might not be)
- Accurate evaluation of differences in efficiency between plants
- Few changes in the market between entering into the agreements, and / or taking account of changing market conditions fairly and appropriately

We understand that SSE does not keep separate records for hedging generation and hedging supply, instead it has power and gas market sales / purchases covering both (c. 174 TWh purchased, c. 165 TWh sold).

If market price data is not readily available or considered appropriate for the transactions SSE enters into, to require the use of market prices for transfer pricing purposes is unlikely to provide a robust result, or may lead to a more complex or less transparent policy as a proxy price is calculated and interposed.

Comparability in the CSS

Having an appropriate transfer pricing policy for its business model does not necessarily result in a comparable position with other groups.

If SSE is compared to E.ON, there is a difference in the level of risk faced by the generation businesses, since the option pricing for E.ON's generation capacity is based on market conditions whereas SSE's is not, although this difference in risk is relatively small. This is again slightly different from RWE npower, where the generation segment can benefit from prompt and balancing market movements and changes in scheduling.

SSE could be directed to follow a different transfer pricing model, such as that employed by Centrica, EDF and Scottish Power with a central trading body acting as a broker for a more complete supply and generation segments. It is not clear whether this would require changes solely on a reporting basis, such as tagging each sale or purchase of gas or electricity as being for 'generation' or 'supply', or whether operational changes would be required.

As this shows, SSE could change its model to be broadly consistent with other groups but may not achieve full comparability due to the more minor differences between all parties' business and transfer pricing models. Consistent year-on-year disclosure, together with transparency in all transfer pricing policies used, may be a more achievable and beneficial aim.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Strengths and weaknesses

Use of wholesale market prices – potential weaknesses

Whether or not operating a toll generation model, generation businesses tend to focus internally at some level on KPIs relating to the efficient management of the generation fleet rather than the price or quantity of output sold.

The use of the wholesale market price exposes these generation businesses to market risk at the time they sell power (or options over power capacity/capability in the case of some toll generation models) and buy fuel and allowances.

This policy could conflict with the management's focus on operational efficiency as power is sold (or hedged) without clear reference to the cost of production, for example when output capability or capacity is hedged into the market. The market prices for future UK electricity are determined by the parties willing to trade at the relevant time – which potentially might lead to speculative influences and cohesive pricing at least at the first points at which trading data becomes available. The timing of these sales is often set by group policies, which will be discussed in more detail below.

The result of this is that these generation businesses are exposed to a degree of market price risk whether or not it is something they would seek to manage under a pure toll generation model. The risk falling within the trading division is correspondingly more limited than where a fixed price is paid for capacity, as seen in some PPAs.

This does not cause an issue for groups using a pure 'central broker' model but leaves levels of risk and reward due to each party to be calculated for other models where at least some risk is transferred. Quantifying and rewarding this risk is not straightforward.

The activities of independent generators and various joint venture partners does not provide a good comparable due to the limitations on how they may approach the market and their bargaining power, or lack thereof, with counterparties. For example, it is broadly accepted that smaller generators would not easily be able to trade on the market as far in advance as larger generators due to perceived credit risk and collateral requirements.

Alternative models – no clear winner

There are several other ways to consider pricing generation output, each of which has its own strengths and weaknesses.

Using market prices as the basis for a comparable gives a clear reference point for analysis, which can be beneficial: any attempt to separate the price that energy can be sold at from the price paid to a generation division creates a potential for profit or loss that must otherwise be carefully matched to functions.

Potential alternatives to this approach include:

- Follow the market facing generator approach, with trading operations acting as lower-risk brokers and making a lower, more stable return based on the provision
- Base the remuneration of generation activities on a fixed base, as SSE currently do, and treat the activities as a 'pure' toll generator

We recommend that the further exploration of these approaches would have merit.

This testing will identify if practical gains may be achieved in either pricing or transparency. This is not guaranteed, for example because the components of a cost-based return would need to be carefully considered to determine a commercially appropriate level of cost. These considerations could include whether they should contain provisions for future plant renovation or how the cost of fuel is calculated.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Strengths and weaknesses

A1.2 - Risk premium

A similar risk of transferring the cost of market risk but not the responsibility for its management arises where businesses charge a 'risk premium' to their generation or supply businesses. The risk premiums used are typically in the order of 1%-2% of the cost of electricity or gas.

The appropriateness of these charges for transfer pricing purposes depends on their purpose.

To the extent that they provide an arm's length level of reward to trading operations for the services and support they provide this may be reasonable, although charges like this are normally seen made on a cost plus basis.

Where this charge in fact represents insurance against risk there needs to be a clear distinction between what is additional risk created by supply activities – which it could be appropriate to charge for – and what creates duplication of charges for risks managed by the trading operation which it either should address internally or are built into its power pricing arrangements. In the latter case, profit may be moved from supply to trading, or the cost base of the supply operations may be increased and potentially included in the calculation of customer pricing.

For example, Scottish Power charges a risk premium fee to its supply business to cover the cost of volume changes between the agreement of the transfer price for energy three days prior to delivery and delivery itself. Where this places potential extra cost requirements on trading due to the forecasting activities of supply, a premium is likely to be reasonable.

To support the use of a premium and the rate applied, the group in question would need to demonstrate that:

- there is a benefit to the 'insured' part of the value chain, in this case generation or supply as relevant; and/or
- there is a probable cost to the 'insurer'; and
- the amounts charged are appropriate based on the risk

For example, a timing difference in setting prices and making transactions could give uncertainty to both parties but if there is no expectation of loss or benefit for one party then the price should not be adjusted for this factor.

We conclude that given the relatively low impact on WACOE and WACOG figures and the existence either of a transfer of risk or of operating costs for providing assistance, this area is relatively opaque but unlikely to cause any material distortion.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Strengths and weaknesses

A1.3 - Speculative trading activities

In addition to hedging generation output and demand, all the main energy businesses except SSE engage in trading either their hedged positions or their generation capacity/capability on the wholesale power market.

This ‘speculative’ trading might be defined as the taking of market positions in pursuit of profit from the trades themselves rather than the management of cost-effective supply for customers.

As this definition suggests, this is not an activity that forms part of the energy supply chain (and not all the large energy companies take part). For transfer pricing purposes care should be taken that pricing policy is not impacted by speculative values, profits or losses, as these would not constitute good comparable data. This impact might be felt through:

- Losses from unsuccessful trading activities being effectively cross-subsidised from energy supply income or profit (or vice versa)
- Market prices used to set group transfer prices incorporating the market’s speculative valuation

Losses from speculative trading activities

Where speculative trading takes place in separate group operations, the transfer pricing policies used are not designed to feed related profits, losses or risks directly back into the energy supply chain. RWE, for example, have a trading operation to deal with the hedging and supply requirements of its generation and supply businesses, and a separate company which takes speculative positions.

However, there is not full clarity regarding where the line between the hedging of positions to minimise risk and the taking of speculative positions is drawn in practice. The trading operations of the energy companies enter into trades for volume in excess of their power generation or supply. This is ascribed to the need to manage hedged positions against market variation, and to meet uncertain demand in the shorter term markets immediately prior to delivery. However, it might be considered that this incorporates taking (and then often reversing) speculative positions as part of this process , the outcomes of which form part of the energy supply chain.

This might be at least partially offset by the matching of generation output and supply within each of these businesses, or this may be performed as far as output allows (eg base load, premium load etc). This may have an impact on the risk profile of the business as it reduces flexibility to manage these positions as market prices change, however it could reduce transaction costs and the need for much additional trading activity. The question of matching output and supply is considered in more detail, below.

Impact of speculative trading on energy market pricing

The use of wholesale energy market prices as the basis for transfer pricing policy raises the possibility that those prices might be influenced by the speculative nature of the market, for example the pricing in of a risk premium by traders, or the movement of prices driven by views on others’ positions in the market.

This is a factor which is difficult to measure. However it supports our recommendation, above, that where market prices are used they are subject to corroboration by a calculation with reference to the cost of generation (although this cost base should be carefully defined), or that a cost-based measure should be in common use for internal pricing arrangements.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Liquidity

A1.4 Timing of hedging policies for generation and supply

When considering the appropriateness of the wholesale energy market price as an effective comparable for transfer pricing purposes, the timing of when that price is taken is an important factor due to both the long-term trend of the market and the tendency of the spark spread to increase closer to delivery.

The energy businesses have group policies regarding hedging, which generally include specifying a time in advance of delivery by which the position should be hedged. Normally this is different for generation selling power into the market and supply drawing requirements out.

Generation tends to hedge its output, capability and capacity earlier than the supply business will hedge its requirements. While the volatile nature of the market supports hedging as a means of managing risk, this gives rise to questions:

- Does generation's earlier hedging lock in any expected/predictable movements in price or spreads over at least part of the curve?
- If so, would a third party company in that position enter into the same transaction at that time?
- Would the matching of internal supply generation and supply requirements at the time of generation's hedge provide a more robust transfer pricing model?

Does generation's earlier hedging lock in any expected/predictable movements in price or spreads over at least part of the curve?

By selling its output, or an option on it, to the market in advance, a generation business can lock in a price against which it can manage its business. This is usually done in stages to obtain optimum results.

However, by engaging in this process significantly in advance of delivery – three years is generally the maximum currently – and in volume, there might be potential to transfer a degree of expected benefit.

By going to market (directly or through a trading operation) at a later stage further along the curve the supply businesses would be locked out of any expected or predictable movements in price by that point. This suggests that the opportunity could exist for trading operations to be intrinsically aligned to make a profit on their activities (ie buying from generation at a lower price than it sells to supply).

As this is based on a view of market trends rather than the volatile day-to-day market, the bias towards a profit in trading operations may be appropriate to reward the risk the latter takes and the capital strength it can bring to the market. However, it may limit the options available to supply businesses.

If so, would a third party company in that position enter into the same transaction at that time?

Independent generators do sell into the market in this way. However, it is not the norm that they sell their whole output or capacity as far ahead in the market. This may be observed from the availability of power from these participants in the short term markets prior to delivery.

Part of this limitation is due to independent generators not having the credit terms to be able to participate at those early stages of the market profitably; this is a benefit accruing to the size of the major players in the industry and for which some of them, for example Centrica, charge their group companies for. However it is also likely that sales in the short term markets are a part of their business strategy.

Depending on the business model, most generation divisions can revise their scheduling plans and buy or sell energy, fuel and allowances to benefit from market movements. Where this does not happen, such as where options are sold over capability, the pricing of options is purported to take into account the value of any expected movements.

There are also reasons that supply businesses might typically hedge later than generators, such as having greater uncertainty over required volumes and prices with customers. For example, a supply business buying three years in advance would be vulnerable to changes in market pricing rendering it unprofitable or uncompetitive against suppliers buying power and gas closer to the time; conversely a generator hedging output has little downside and can sell back its positions if spreads decrease.

Differences between when different types of business, for example the Big Six or smaller independent suppliers, seek to go to market would be a probable factor behind any tendency for movements in pricing along curves as demand varies.

APPENDIX A.1 – TRANSFER PRICING COMPARISON

Liquidity

Would the matching of internal supply generation and supply requirements at the time of generation's hedge provide a more robust transfer pricing model?

If both generation and supply divisions were to match their output and requirements at the time generation would normally hedge under current policies, at least for the most predictable base and peak load, this would reduce the involvement of energy companies' trading divisions and so increase clarity of reporting.

Whether this lowers the input cost to the supply business or simply transfers risk from trading to supply is likely to depend on the nature of current trading operation activities.

Many groups adjust their forecasts and hedged positions on a frequent basis leading to often buying back/reselling gas and/or electricity. The extent to which this is a prudent strategy compared to taking a position and only adjusting hedged positions infrequently or near the time of delivery could be explored. For example, EDF Energy's supply division makes gross purchases from EDF Trading (which excludes orders matched with the generation division) of on average 1.5 times the ultimately required electricity for customers due to making numerous adjustments to its forecasts and thus hedged positions. By seeking to trade with the market in isolation of internal group requirements, hedging activities could appear speculative. As discussed, this potentially reduces the ability of market prices to be supported as robust transfer pricing comparable data.

The extent to which matching internal generation and supply on predictable load could be beneficial for consumer prices or reporting might be profitably examined in the context of hedging activity undertaken by trading operations.

APPENDIX A.1 – TRANSFER PRICING COMPARISON

How shaping is dealt with

OVERVIEW	CENTRICA	EDF ENERGY	E.ON	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
Sales to/from generation	Generation and supply teams work with Centrica Energy Limited to negotiate prices with counterparties to acquire/sell the desired shaping. Generation can choose to sell to supply if it considers the price to be right	Only instruments that are being traded at the time are used; eg flat volumes a long distance out	Generation capacity is sold on an option basis, which should take potential demand shape into consideration	Generation capability is sold on an option basis, which should take potential demand shape into consideration	Demand shaping is not relevant for SSE's pricing	Only instruments that are being traded at the time are used; eg flat volumes a long distance out
Sales to/from supply			Pricing for shaped products is modelled based on the available instruments	Only instruments that are being traded at the time are used; eg flat volumes a long distance out		

Table A.1.4 – Comparison summary of how shaping is dealt with

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Incentives to manipulate transfer pricing

Introduction

As noted in previous slides, one of the main concerns of tax authorities in relation to transfer pricing tends to be that pricing within a group has been manipulated in order to result in profits being diverted into a low (or no) tax jurisdiction.

We have explored several potential drivers for the Big Six to manipulate their transfer pricing to intentionally divert income and profits to or from certain companies or divisions, as well as safeguards which may be in place to deter it. As discussed below, we conclude that there are no obvious incentives.

It is worth noting that whether or not a clear motive exists is distinct from whether or not any intentional bias has been built into a pricing policy; similarly the absence of an intentional bias does not mean that arm's length pricing has been used.

In particular, the overall structure of a group might have been influenced by particular factors (eg whether to locate a trading entity in the UK or overseas or how risk adverse each part of the business should be), which would not necessarily cause concern from a transfer pricing perspective so long as the pricing appropriately reflects the location of actual functions, risks and assets.

This section should therefore be read in conjunction with our assessment of the strengths and weaknesses of the various models.

Tax motives

Most intragroup transactions take place within the UK, including where an overseas trading body operates through a UK branch, and hence there is unlikely to be any significant impact of these policies on the overall UK tax position.

Where an overseas trading partner is involved, this is broadly limited to France or Germany, both of which charge a higher level of corporation tax than the UK. This means that there could only be a tax incentive to shift profits centrally if there were significant tax losses within that country, whether historic or from an ongoing loss-making business. We have not been able to identify whether this might apply and it could be unfeasible to do so in terms of future profitability of other businesses.

Central trading entities, wherever located, that undertake speculative trading might be expected to occasionally make losses that could potentially shelter taxable profits. This is unlikely to drive a policy for tax reasons, as groups are likely to expect that the activity will be profitable and certain group/consolidation reliefs might be available for tax purposes in any case without needing to manipulate pricing. From a regulatory perspective however there might be an incentive to decrease the likelihood of making losses in a trading entity, for example to maintain regulatory capital levels.

CSS transparency

It is feasible that intragroup pricing could be manipulated with the express intent of disguising results such as WACOE for supply. However, with the exception of SSE, most business models and transfer pricing policies have not been drawn up expressly for CSS purposes meaning this could be at most an ancillary purpose to 'tweak' the model used.

This area is particularly hard to assess motives for. However, where a consistent pricing policy is used internationally, this could be expected to make this motive less relevant. Where pricing with trading divisions is consistent for both generation and supply and/or for buying and selling transactions the scope for this manipulation is restricted to fees and premiums.

Other motives

There may be other influences, for instance the culture of the parent company might favour the repatriation of cash regardless of tax rates, or local reporting requirements etc.

Barriers to manipulation

For the most part, where market based pricing is used, we have been told that both parties will test the prices and have a degree of self-interest. Some groups have a degree of central oversight that purports to ensure negotiations between divisions are conducted on a fair and balanced basis.

Furthermore, the methods used are typically similar for buy and sell transactions (exceptions being cost based or aggregated calculations, brokerage fees and option pricing) limiting the options for biasing the position.

From a commercial perspective, if unfair pricing was intentionally used and this came to light there could be significant bad publicity, making it a somewhat risky policy.

Conclusion

Whilst we cannot definitively rule out any intentional manipulation of transfer pricing policy, we have found no clear motive for any of the Big Six to do this and the barriers to such intentional manipulation seem sufficient to make it unlikely.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Potential changes to segmental reports

Inclusion of trading division

Given that currently trading entities/divisions represent a 'missing link' between the generation segment and the WACOE/WACOG shown in the supply segments, reporting of the trading operations would increase transparency.

For such inclusion to be helpful, it would need to separate out speculative trading and show only profits and losses relating to the generation or supply businesses. For example, where E.ON's generation business sells options to its trading arm this allows EET to hedge and change scheduling plans for its own benefit, with this portfolio being distinct from the supply portfolio and speculative trading. The results solely of this part of EET's business would likely be possible for it to calculate, for example:

- The net income from trades for that portfolio
- The cost of purchasing options from generation
- Indirect costs

There are however, a number of obstacles to implementing this approach. Firstly there is a chance that the data is either unavailable due to not being recorded, or prohibitively burdensome to extract and present. There would also be a high likelihood of pushback from the Big Six, even if the data was available for them. The UK entities of the Big Six are likely to have no legal authority to request this data from overseas group members.

Uniform inclusion/exclusion of free allowances

Most groups allow the benefit of allocations under the NAP to impact their CSS figures, whereas Scottish Power adds the benefit back in. Scottish Power is as a result the most transparent about the value of these allowances, but there seems to be little reason to have disparity on this issue.

Due to the calculations used, SSE's figures are likely to include this benefit in the supply segments; however it would be possible for them to reallocate these to generation (for allowances relating to those plants that they own and include in the generation segment).

Consistency of fuel costs for generation

SSE shows only a capacity payment for its plants, which is entirely unaffected by volumes actually produced.

RWE models its generation business income as the sale of options and therefore presents its effective gross profit on generation rather than showing the sales value of the volumes produced and the cost of production. E.ON follows a similar model, which if anything is slightly closer to SSE's as its generation business has no interaction with the prompt or balancing markets – yet its generation segment does show fuel costs flowing in and out.

It would seem possible for SSE and RWE to include fuel costs in their generation segment; however they would likely consider it to be inconsistent with their business models. It should only be considered therefore if WACOE for the generation businesses is something that would be useful to have shown in all statements. This is discussed in more detail on the following page.

If the purpose of the generation segment is to assess whether or not a group is diverting profits to its generation business at the expense of supply, this measure would be of no benefit.

Notional adjustment to reflect a single business model

The possibility of requiring all groups to follow a single transfer pricing policy for the purposes of the CSS was considered as one of the four remedies considered as part of the original Probe. Given the way the businesses are actually structured, this could be particularly difficult to achieve without in fact making the segmental reports less transparent.

The only option that would seem practical for a uniform policy would be to follow SSE's approach for generation and assigning a fixed return to each power station, and follow the other groups' approach to the supply segments with the remainder left in a 'trading and scheduling' segment. This would not seem to give any advantage over the current reports. We agree with the conclusion of the relevant part of the Probe, that a notional adjustment to a common business model is not advisable.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Further detail relating to fuel costs

Fuel costs are currently not treated consistently by the Big Six; only some include these in generation business results. A common treatment could increase transparency in CSS reporting.

This would require changes by RWE npower and SSE. Both could add in a cost of fuel and allowances for generation with a matching increase to revenue, alternatively SSE could rework its model entirely. We assumed the option of adding fuel costs in our discussion below.

Impact if fuel costs included in CSS

The first stage of evaluating whether to require fuel costs to be included in the CSS for generation activities is to consider what the resulting segment would show or include. The segments (including additional fuel costs / income where relevant) would include:

- For Centrica, EDF and ScottishPower the segment would be as it is currently. This includes:
  - Own generation, based on market pricing at time of hedging
  - Generation through PPAs
  - Any impact of scheduling (such as adjustment of hedging) and balancing market activity
- For SSE there would presumably be an apportionment of total gas costs added to the generation segment with revenues increased by a similar amount. This would result in income showing:
  - Fixed capacity income, based on efficiency of plant and pricing on PPAs
  - Variable costs reimbursed under PPA arrangement
  - Cost of gas (which will be slightly lower than that shown for the domestic supply segment if using a consistent calculation method with 2010) plus allowances
- For RWE npower, the gas cost would either be extracted from RWEST's accounting systems, or otherwise estimated. The resulting income would show:
  - Capability options, based on market pricing at time of hedging and estimate of the benefit of scheduling/flexibility
  - Short term changes to scheduling
  - Cost of gas / allowances
- E.ON currently shows something similar to that which RWE npower might produce, but excluding any short term scheduling changes / prompt or balancing market activity

Would this improve comparability?

The revised generation segments for SSE, RWE npower and E.ON would combine elements of variable income with a significant element of fixed income from the sale of capacity or capability options.

- This would not prevent the WACOE being calculated in a consistent way to other segments, nor should it have a material impact on what the WACOE figure represents
- The income per MWh produced might be highly variable depending on actual production. This could cause confusion
  - For example, should the market position be such that the power stations are run less than expected, the income per MWh might appear high
  - However, other elements such as renewable generation or nuclear power already cause variations in the income per MWh and it is questionable whether distortion from adjusting SSE's and RWE's results would be any greater than these existing variations
- The trading segments would still bear the cost of optimisation teams responsible for scheduling plant, potentially causing some level of non-comparability between groups at the indirect cost level.

Income in further detail

- The fixed income of SSE's generation segment is comparable to a cost borne by other generation segments and this in particular could lead to questions over relevance of any comparison.
- The option arrangements of E.ON and RWE will take into account the expected profitability of trading in and out of positions as market prices and scheduling plans change. It is probable that the capacity fees for SSE will reflect this to a degree although will be somewhat less flexible.
- Therefore on average the income ought to be broadly comparable, less amounts to cover risk and functions undertaken by the trading or supply parts of the business.

APPENDIX A.1 – TRANSFER PRICING COMPARISON
Further detail relating to fuel costs

Feasibility

SSE's model could be adjusted quite flexibly to show this figure; however given that RWE npower and RWEST do not currently show these amounts, it is not clear whether it would be practical for them to draw them out.

Whereas E.ON and EET record a market price at the time fuel and allowances are transferred to E.ON or utilised, there is no evidence that this takes place within the RWE npower group. This could result in the gas cost being either estimated or a requirement being put in place for RWEST's accounting system to be examined to calculate a WACOG. If the trades relating to the generation portfolio are separately tagged in the systems, this may be possible.

Presumably the net cost of net fuel purchases would be a relevant measure to use, taking into account any changes in hedging / scheduling, in order to have a comparable WACOG as to the likes of Centrica and EDF, rather than seeking to identify a market cost of the gas actually used, as E.ON does.

The main difficulties will arise because:

- For RWE npower, this might not be a simple exercise and the UK companies are unlikely to have any right to oblige RWEST to provide this information
- RWE npower and SSE are both likely to challenge the relevance of fuel costs given their business models largely separate the performance of generation from the volumes of power actually produced

APPENDIX A.2 - HEDGING AND DERIVATIVES COMPARISON

APPENDIX A.2 – HEDGING AND DERIVATIVES COMPARISON
Overview

Accounting for longer term hedges and derivative contracts

Energy companies enter into arrangements where they commit either to buy or sell energy in the future. This occurs both in their generation activities, where they need to ensure that they can sell what they produce and effectively use their capacity, and in their supply activities, when they must be sure of being able to meet consumer demand need too.

Accounting standards

From the point of view of published financial statements, these arrangements potentially give rise to financial instruments for which the accounting rules are set out under International Financial Reporting Standards (IFRS) in *IAS 32 Financial instruments: Presentation* and *IAS 39 Financial Instruments: Recognition and Measurement*.

There are equivalent standards in UK: GAAP FRS 25 (IAS 32) and FRS 26 (IAS 39). These are in effect the same standards adapted for the UK, although the application of FRS 26 is only required for a listed entity or where fair value is otherwise used in the accounts.

IAS 39 requires that Financial Instruments (except for certain types of debt) are stated at fair value. Fair value is categorised between level 1, directly observable from quoted market prices for identical assets, level 2 derived from inputs observable from the assets or liabilities or level 3 based on valuation techniques that include data not based on observable market data.

The types of arrangement referred to above are specifically scoped into the requirements of IAS 39 which require the standards to be applied to ‘those contracts to buy or sell a non financial item that can be settled net in cash or another financial instrument’.

As IAS 39 requires that where such instruments are carried at fair value that any differences in value, either from acquisition or from the previous set of statements, are taken to the income statement as this would potentially have a very big effect on the financial statements of the energy companies.

However there are two reasons why this is not the case.

- **Own use exemption** - Firstly, there is an exemption from the standard for contracts which are ‘entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the entity’s expected purchase, sale or usage requirements’. This is the ‘own use’ exemption which for generating and supply activities will in most cases apply. This would not be the case for trading activities
- **Hedging treatment** - Secondly, if the arrangement can be established to be an effective hedge then although the changes in fair value are recognised, there is no income statement effect

Residual instruments

For those arrangements which cannot take advantage of the above, there would be expected to be an income statement effect. For example, EDF Energy acquired some generating companies with pre-existing forward supply contracts which had to be re-valued on acquisition (under the accounting rules for acquisitions). These were carried forward at fair value with the differences going to the income statement.

CSS

For the CSS being considered in this report all of these income statement movements relating to these residual instruments were excluded and feature as items on the reconciliation statements. This ensures consistent treatment across the Big Six firms as it would not be comparable if some companies accounted for these movements and others did not. The effect of this is that the CSS show all the profits and losses attributable to the sales and purchases delivered in the year. This ignores value changes of forward positions from year to year.

Overall findings

Our overall findings are very much as we would have expected, which is that despite extensive use of forward contracts, futures and other hedging arrangements, from an accounting point of view these are ignored for the CSS for generation and supply. This is either through the own use exemption, hedging treatment or, in the absence of that, have been excluded from the CSS and appear on the reconciliations. Based on our review, we have found that there is no apparent lack of comparability as a result of the accounting treatment of such arrangements.

APPENDIX A.2 – HEDGING AND DERIVATIVES COMPARISON
Comparison table

OVERVIEW	CENTRICA	EDF ENERGY	E.ON	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
GAAP adopted for segmental reporting	IFRS	IFRS	IFRS	UK GAAP	IFRS	IFRS
CSS reconciliation	Revenue and EBIT are reconciled to the Centrica Plc Annual Report Segmental Analysis. Volumes are reconciled to the Centrica Plc Annual Report Business Review.	EBITDA is reconciled to the EDF Group Document de Reference Segmental Analysis.	EBIT is reconciled to E.ON UK Plc Annual Report and Accounts Segmental Result.	Turnover, total costs and EBIT are reconciled to an aggregation of the individual statutory accounts of the legal entities that held a relevant licence.	EBIT is reconciled to Scottish and Southern Energy's Annual Report Segmental Information.	Each line item in the CSS is reconciled to an aggregation of the individual statutory accounts of the legal entities that held a relevant licence.
Fair value accounting adopted in statutory financial statements	Yes	Yes	Yes	No	Yes	Yes
Fair value adjustments excluded from the CSS	Yes	Yes	Yes	Yes	Yes	Yes
Fair value methodology	Open market values and valuation models, subject to hedge accounting and own use exemptions.	Open market values and valuation models, subject to hedge accounting and own use exemptions.	Open market values and valuation models, subject to hedge accounting and own use exemptions.	N/A	Open market values and valuation models, subject to hedge accounting and own use exemptions.	Open market values and valuation models, subject to hedge accounting and own use exemptions.

Table A.2.1 – Hedging and derivatives fair value methodology comparison

APPENDIX A.3 – ENERGY TRADING COMPARISON

APPENDIX A.3 – ENERGY TRADING COMPARISON

The speculative energy trading activities within each of the Big Six, have been excluded from the CSS mainly due to the way that each company structures its business model. There are however, indirect costs and allocation of expenses resulting from these trading activities that are included within the CSS with adjustments for transfer pricing and hedging activities. To this end we refer to the comparisons in relation to this trading activity within the main body of this report.

All of the companies appear to have revaluation accounting techniques to re-measure certain forward contracts at 'fair value' at year end. These results are consistently excluded across the companies in their CSS and thus provide clarity and consistency of treatment.

Of the companies that do not have UK trading entities, there is no disclosure of UK trading results in either the CSS or the UK level reconciliation.

Below is an overview of the trading activities of each of the companies studied as part of this review.

British Gas/Centrica

Energy trading represents a very small part of the business. For 2010 the financial statements show a separate segment with revenue of £2m. In 2011 proprietary energy trading will be amalgamated with the upstream business.

Speculative trading is captured through separate ledger codes in the accounting system and not included in the CSS.

EDF Energy

EDF Energy does not undertake speculative trading activities. The risk mandate precludes taking any directional positions on the market. EDF Energy’s target is to reach the Minimum Intrinsic Risk Position before entering the budget year (12 months ahead). As a result, all trades entered into are done with the express intent of hedging the portfolio of assets. Most external transactions are performed with EDF Trading via arm’s length agreements.

E.ON

[✂] In the CSS E.ON refer to their transfer pricing methodology to ensure that transactions between Germany and the UK are at arms length.

We refer to the transfer pricing section for further discussions of the methodology.

RWE npower

All energy trading is conducted within RWEST and the results are excluded from the CSS. In the CSS RWE refers to their transfer pricing methodology to ensure that transactions between RWEST and the RWE UK are at arms length. We refer to the transfer pricing section for further discussions of the methodology.

Scottish and Southern Energy

All trading is done though the Energy Management Division, which is not included in the CSS with the exception of a small amount derived from Renewable Energy transactions. Generation receives its income from providing capacity to wholesale energy trading through Power Purchase Agreements (PPAs). The PPA charges are based on market rates multiplied by the amount of availability during the year plus a variable cost charge based on output. Actual output for renewable energy (wind and hydro) is charged at market rates.

ScottishPower

Energy trading represents a small part of the business. [✂]

Speculative trading is captured through separate ledger codes in the accounting system and not included in the CSS. Trades in relation to the balancing mechanism are allocated to electricity supply on the same basis as other costs (see transfer pricing for further details).

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON

What are exceptional items?

A number of the energy companies have highlighted items as exceptional for the purpose of the CSS. This term must be used carefully as it means different things in different contexts.

In relation to financial statements drawn up under IFRS there in fact is no concept of exceptional items. Companies are required to present additional line items, headings and sub totals where these are relevant to the understanding of the financial statements. Even in UK GAAP, where this concept exists, it only relates to items which need to be separately disclosed because of their size or incidence if the financial statements are to show a true and fair view. Therefore, the term, where it is used, is used as a means of emphasising an item included in the measurement of profit.

In the CSS this is being used in a different way. In effect it is being used by some companies to describe items which have been excluded from the CSS. The issue is further confused in that other companies have similar items which they do not describe as exceptional. This tends to confuse the issue when reviewing the reconciliation statements and these items tend to be included in the reconciliation statements alongside other items which are of a different nature.

Starting point of reconciliation

In wider sense this issue should be looked at in the context of all the reconciling items between audited financial statements and the CSS. Before looking at the items it should be noted that the statements themselves start in different places. There are two basic approaches (see table A.4.1).

These are to start with either:

- The audited Income statement or an aggregation of audited income statements; or
- A segmental note in a published statement - derived from the income statement but which may contain adjustments which are not shown in CSS.

The advantages of going directly from audited statements are that the reconciliation is directly to an audited number but even here may be differences depending on which line a company reconciles to (ie EBIT or EBITDA) and also one of the companies uses a columnar approach which excludes exceptionals on face of income statement and then reconciles to the figure ‘after exceptionals’.

Nature of adjustments shown in reconciliation in CSS

On table A.4.3 we have analysed the adjustments into two main categories being:

- ‘Discretionary’ – those adjustments made to make EBIT or EBITDA give better information by excluding items of a one off nature; and
- Because of need to comply with requirements of drawing up CSS (eg excluding unlicensed entities).

The first category relates to adjustments which are made by companies to exclude items presumably because they are not considered relevant to the purposes of the statements. There is nothing wrong with this approach as long as the purpose of the statements is agreed and the adjustments make the statements fulfil this purpose in a better way. However, the risk is that the companies’ understanding of the purpose of the statements may be different to OFGEM’s understanding.

Indirect costs

The entities use a variety of different cost allocation methods in respect of their indirect costs. [✂] it would appear that the method of cost allocation may be appropriate for the size and nature of each entities operations. However, we are unable to conclude on the indirect cost allocation without conducting more work in this area.

Coterminous reporting dates

On page 54, we have considered the possibility of establishing coterminous reporting dates for the CSS. However, each possibility would be at significant cost to at least one or more of the entities.

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON
Details of reconciliation

In preparing the CSS the entities have presented a number of reconciling items.

- Set out below are details of the reconciliation process for each entity:

	CENTRICA	EDF ENERGY	e.on	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
CSS reconciles to financial statements segmental analysis	✓ 1	✓ 2	✓ 3	-	✓ 4	-
CSS reconciles to individual subsidiary accounts	-	-	-	✓	-	✓

Items reconciled: [1] To Centrica PLC Annual Report
[2] To EDF Documents de référence
[3] To E.ON UK PLC Annual Report
[4] To Scottish and Southern Energy plc Annual Report

Table A.4.1 - Details of reconciliation process

	CENTRICA	EDF ENERGY	e.on	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
Revenue	✓	-	-	✓	-	✓
EBITDA	-	✓	-	-	-	✓
EBIT	✓	-	✓	✓	✓	✓

Table A.4.2 - Items reconciled

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON
Exceptional items comparison table

Neither Centrica, EDF Energy nor ScottishPower explicitly refer to the term 'exceptional' within their CSS whereas E.ON, RWE npower and SSE do use the term 'exceptional'. The number and type of reconciling items is largely dependent upon the basis of GAAP adopted and the audited documentation to which the CSS is reconciled to. As there is little or no similarly on these factors, the number and type of reconciling items varies significantly.

	CENTRICA	EDF ENERGY	e.on	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
GAAP adopted for segmental reporting	IFRS	IFRS	IFRS	UK GAAP *	IFRS	IFRS
Treatment of exceptionals within statutory financial statements	Exceptional items are analysed into a separate column within the income statement.	No separate analysis of exceptional items.	Separate line item in the income statement for contract provisions, impairment and restructuring costs.	Separate line item in the profit and loss for exceptionals.	Exceptional items are analysed into a separate column within the income statement.	No separate analysis of exceptional items.
Items explicitly referred to as exceptional in the CSS	No	No	Yes	Yes	Yes	No
Discretionary items:						
Emissions/carbon permits	-	-	-	-	-	Yes
Certain finance leases adjusted for	-	-	-	-	Yes	-
Asset impairments adjusted for	-	-	Yes (and disclosed as exceptional items).	-	Yes (and disclosed as exceptional items).	-
Restructuring costs adjusted for	-	-	Yes (and disclosed as exceptional items).	Yes (and disclosed as exceptional items).	-	-
Onerous contracts adjusted for	-	-	Yes	-	-	-

Note: * Although, the main differences between the CSS template (prepared under UK GAAP) and the operating result disclosed in the RWE AG Annual Report (prepared under IFRS) are disclosed.

Table A.4.3 – Adjustments made during reconciliation

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON
Exceptional items comparison table

	CENTRICA	EDF ENERGY	e.on	RWE NPOWER	SCOTTISH AND SOUTHERN ENERGY	SCOTTISHPOWER
Required reanalysis to get to the correct starting position:						
Minority interests, joint ventures and associates adjusted for	Yes	-	-	-	Yes	Yes
Inter-segment reallocation adjusted for	Yes	-	Yes	Yes	-	-
Overseas businesses adjusted for	Yes	-	-	-	Yes	-
Disposal of business units adjusted for	-	Yes	-	-	-	-
Business units with no generation or supply activities excluded	-	Yes	-	Yes	Yes	Yes
Fair value adjustments resulting from business acquisitions excluded	-	Yes	-	-	-	-
Allocation of corporate overheads adjusted for	-	-	Yes	-	-	-
Net derivative gains/mark to market adjustments	-	-	Yes	-	-	Yes

Table A.4.3 – Adjustments made during reconciliation cont.

APPENDIX A.4 – EXCEPTIONAL ITEMS COMPARISON
Indirect costs comparison table

In preparing the CSS, each of the entities provides a description on how indirect costs are analysed between generation, supply and other segments. Due to the differing types of vertical integration with each business and the differing cost absorption models employed, the type, nature and allocation method of indirect costs vary from entity to entity.

Activity based costing aims to assign overhead costs to product/services in a more logical manner than the traditional approach of simply allocating costs on the basis of revenue or staff numbers. Activity based costing first assigns costs to the activities that are the real cause of the overhead. It then assigns the cost of those activities only to the products that are actually demanding the activities. Our findings on indirect costs are considered further on pages 12, 13 and 48 of this report.

	CENTRICA	EDF ENERGY	e.on	RWE NPOWER	SCOTTISHPOWER	SCOTTISH AND SOUTHERN ENERGY
Examples of main types of indirect costs	Sales and marketing costs, bad debt, costs to serve, IT, staffing costs, billing and all meter costs.	Metering charges (net of income received), staff costs, property costs, head office recharges, bad debt expense, etc.	Sales and marketing costs, bad debt, costs to serve, IT, staffing costs, billing and all meter costs, general office costs, repairs and maintenance and central brand development.	Directly attributable station operating and maintenance costs and the generation segment's share of common costs.	Head office costs, staff costs, non operational plant costs, and the costs of centralized services, costs of billing, metering, customer service, debt collection, support services, sales and marketing staff costs.	Salaries and other people costs, maintenance, rates, corporate costs, IT charges, sales and marketing, customer service, bad debts, supply costs, corporate recharges - including information technology and telecoms costs, metering asset and meter reading costs.
Types of allocation method	Direct allocation or based on various drivers such as customer numbers, number of employees, or sales.	Direct allocation or based on specific key drivers for the various costs concerned, such as usage relating to each service; on an equitable basis across the business units; or by appropriate cost drivers.	Direct allocation or on an activity based costing methodology.	Direct allocation or on an activity based costing methodology.	Direct allocation or based on a basket of indicators of revenue, operating profits, net assets and employee numbers, budget centres, cost types and customer numbers.	Direct allocation or by costing models based on activity, customer billing or customer numbers.

Table A.4.4 – Indirect costs allocation comparison

APPENDIX A.5 -RECOMMENDATIONS - FURTHER INFORMATION

APPENDIX A.5 -RECOMMENDATIONS – FURTHER INFORMATION

Impact of Recommendations 1 and 3

Overview

Further to the details included in Section 3 of this report, the table below provide a high level overview of the proposed recommendations R1 and R3 and their potential impact on the Big Six.

	CENTRICA	EDF ENERGY	E.ON	RWE NPOWER	SCOTTISH POWER	SSE
R1 - Additional cost of preparing the segmental statement to 31 December	Nil					High
	Already prepared to 31 December					No publicly available information to 31 December is produced
R1 - Additional cost of preparing the segmental statement to 30 June	Medium					High
	Interim financial reports to 30 June are produced					No publicly available information to 30 June is produced
R3 - Additional cost of reconciling the segmental statement to individual licensed company IFRS accounts	High				Low	High
	Individual licensed company accounts are not prepared under IFRS				Individual licensed company accounts are prepared under IFRS	Individual licensed company accounts are not prepared under IFRS
R3 - Additional cost of reconciling the segmental statement to individual licensed company UK GAAP fair value accounts	Low			High	High	Low
	Individual licensed company accounts are prepared under UK GAAP			Individual licensed company accounts are prepared under UK GAAP but not on a fair value basis	Individual licensed company accounts are prepared under IFRS	Individual licensed company accounts are prepared under UK GAAP
R3 - Additional cost of reconciling the segmental statement to UK parent company consolidated UK GAAP accounts	High			Low	High	
	UK consolidated accounts are prepared under IFRS			UK consolidated accounts are prepared under UK GAAP	UK consolidated accounts are prepared under IFRS	
R3 - Additional cost of reconciling the segmental statement to UK parent company consolidated IFRS accounts	Low			High	Low	
	Consolidated IFRS accounts prepared at UK parent level			No consolidated IFRS accounts prepared at UK parent level	Consolidated IFRS accounts prepared at UK parent level	
R1 and R3 - Additional cost of preparing the segmental statement to 31 December and additional cost of reconciling the segmental statement to UK parent company consolidated IFRS accounts	Nil			High	Nil	High
	Already prepared to 31 December and consolidated accounts prepared at UK level			Accounts already prepared to 31 December but no consolidated IFRS accounts prepared at UK level	Already prepared to 31 December and consolidated accounts prepared at UK level	Consolidated IFRS accounts prepared at UK level but no publicly available information to 31 December is produced

Table A.5.1 - Additional costs to companies of R1 or R3

APPENDIX A.6 - HIGH LEVEL RESPONSE TO ITT SECTION 2.4

APPENDIX A.6 - HIGH LEVEL RESPONSE TO ITT SECTION 2.4

Overview

Overview

As part of this report, we have covered the specific detail related to the questions set out below in more detail in the hedging and derivatives and exceptional items sections of this report. Our opinions on the below have been limited by the level of detail that we have investigated each company. As our work was not a forensic audit, all conclusions and interpretations have been based on management representations and data supplied by the Big Six. We have not performed any work to corroborate this data by way of using third party sources of data or more detailed investigation.

2.4.a - Identify whether any profits are being inappropriately excluded from the Segmental Statements

It is our opinion that no evidence has been presented to us that profits are being unduly excluded from the CSS, due to reporting policies or procedures for any of the companies reviewed. Our recommendations in section 3 of this report have identified areas where we think further transparency and clarity around profit levels can be achieved, specifically the adoption of a common reconciling point (R8) and more detailed guidance on the classification of exceptional items (R7).

2.4.b - Assess whether the existing company approaches are likely to present a true and fair view of the segmental split of profitability

It is our opinion that we have seen no evidence that would suggest that the CSS to not present a true and fair view of the split of profitability. We do not believe that the current CSS demonstrate that any of the companies are engaged in activities to purposefully mislead or cloud the view of the profits generated by different segments, however, key recommendations that we have suggested that could improve confidence in the CSS would be to require the trading functions' results to be reported, with disclosure of any risk premiums applied (R4) and also to test the wholesale market prices used as the basis of transfer pricing decisions (R5). Our understanding is that the transfer pricing policies in place within each company, demonstrate that they are fit for purpose and transparent.

2.4.c - Assess the impact arising from the application of varying accounting principles (including those related to other jurisdictions), allocation rules, and business models

The impact of the different business models employed by each of the companies has been reviewed in more detail in Appendix B of this report. Our opinion is that the models in place by each of the companies, are broadly similar and are demonstrative of good practice. Accounting principles across the companies are consistent in their application, with 5 of the 6 companies reporting results under IFRS conditions and treatments. Our opinion is that the impact of these varying business models is not sufficient to warrant any significant changes to the way the businesses are structured

2.4.d - Recommend any changes which would improve the usefulness of the Segmental Statements, including increasing company cross-comparability

Within section 3 of this report we have identified the 8 recommendations that we feel will help improve the CSS provided by the Big Six. Of these, the following six we feel will help improve the cross-comparability are:

R1. Require the Big Six to publish their CSS at the same time and to the same year-end

R2. Appoint an independent auditor to provide an opinion on the statements each year.

R3. Instruct the Big Six to reconcile their CSS to an audited IFRS Income Statement.

R6. Introduce a uniform reporting treatment for common recurring items in the CSS, in particular free allowances and fuel costs

R7. OFGEM to provide more detailed guidance on the scope and definition of exceptional items

R8. OFGEM to instruct the Big Six to reconcile the CSS to the same starting point

Further details of these can be found on pages 15 – 22.