Transmission Pricing Methodology: Beneficiary Pays Options

Report to Genesis Energy

March
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Acronyms and Abbreviations

CUWLP	Clutha Upper Waitaki Lines Project
FERC	Federal Energy Regulatory Commission
GIT	Grid Investment Test (now known as the Investment Test)
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PJM	Pennsylvania-New Jersey-Maryland Regional Transmission Organization
RTOs	Regional Transmission Organizations
SPD	Scheduling, Pricing and Dispatch
TPM	Transmission Pricing Methodology

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Executive Summary

The Electricity Authority first suggested using a beneficiary pays approach to transmission pricing in its October 2012 proposal. This gave rise to significant industry concerns on how the proposed Scheduling, Price and Dispatch (SPD) charge would be implemented, and what impacts the SPD charge would have. In response, the Electricity Authority has released a working paper that focuses on beneficiary pays transmission pricing. Genesis Energy has engaged Castalia to comment on the Electricity Authority's working paper, specifically to consider whether the selection and evaluation of options is complete and accurately characterises the likely impacts of beneficiary pays pricing.

The material presented in the working paper shows that the Authority has put effort into developing variations of the SPD charging approach that it signalled in October 2012. In our view this is not the best use of resources. While many of the changes made to the SPD are improvements, the Authority's focus on tweaking the design of the SPD charge considerably narrows the scope of the working paper. Proposing various ways to implement the SPD charge misses an important opportunity to review the full range of beneficiary pays options available, and how different approaches would change efficiency in the electricity sector.

This paper presents much of the material we believe should have been covered in the Authority's working paper. Specifically, we identify a broader range of options to implement a beneficiary pays approach to transmission pricing and we discuss their strengths and weaknesses. We also evaluate which approaches appear to have the most merit based on their likely impacts on efficiency.

The working paper fails to explore a sufficient range of options

The working paper focused on beneficiary pays options that use actual market outcomes to determine benefits and beneficiaries (an ex-post approach to setting transmission prices). However, this is only one approach to beneficiary pays. Other approaches, such as using forecasts of market outcomes or power flow analysis, have been largely ignored by the Authority. Different approaches have very contrasting strengths and weaknesses, and therefore need to be explored to build a complete understanding of the best way forward. The narrow range of options considered in the working paper is remarkable in failing to consider the beneficiary pays pricing approaches used overseas.

The complete absence of information on overseas experience is a real weakness of the working paper. Some of the best minds in the world have been grappling with how to implement beneficiary pays transmission pricing in the United States, following the release of FERC Order 1000 in 2012. The working paper does not even mention those developments. We cover that ground in this report based on our independent research of experience with beneficiary pays transmission pricing in the United States.

This research leads us to conclude that an option not considered by the Authority would better promote efficient outcomes. That option is an "area of benefit" approach, which models market interactions to forecast the benefits that transmission assets are expected to provide at grid exit points or in particular regions. The Grid Investment Test (GIT) (now known as the Investment Test in the Transpower capex input methodology) used in New Zealand to approve new transmission investment uses the same modelling approach to determine whether investments provide net benefits overall.

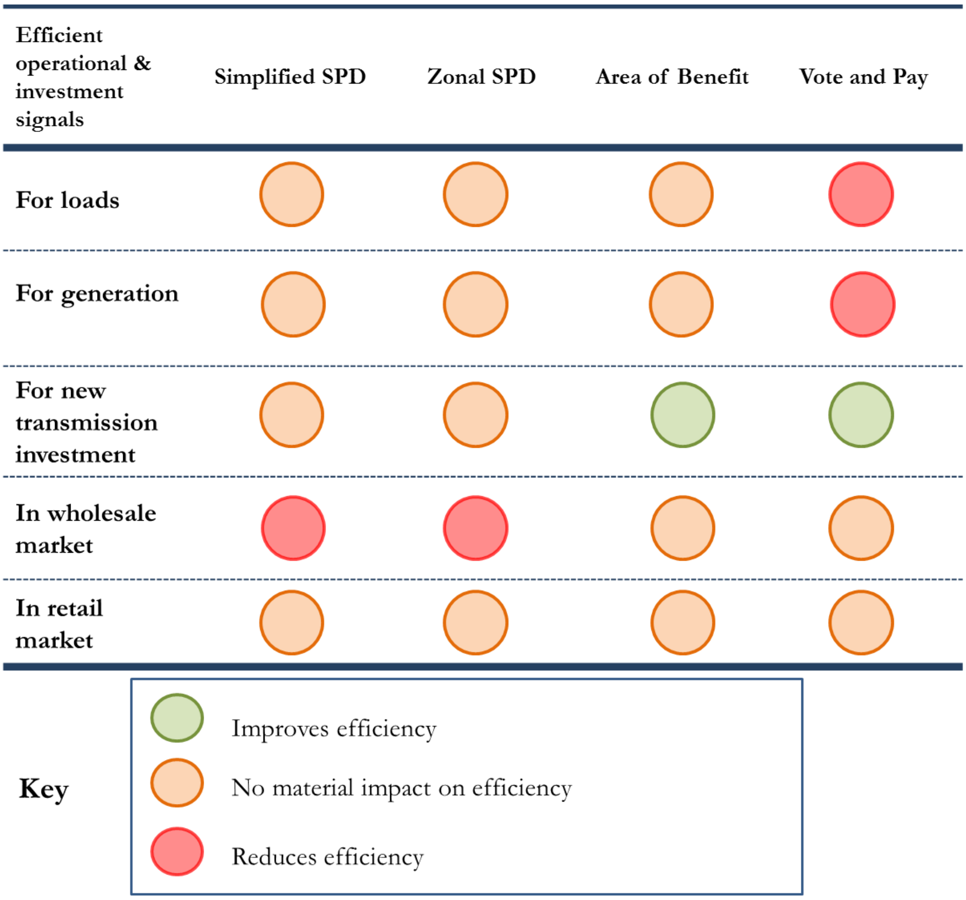
The working paper does present one option where part of the pricing approach uses an area of benefit analysis. This is the GIT-plus-SPD approach. Under that approach, the cost of reliability investments is allocated based on forecasts of the benefits that are expected in particular areas. In this paper, we extend that approach to also include economic investments. We see no reason why economic investments cannot be covered by such an approach. Indeed, an area of benefit approach is being successfully applied to economic investments in the parts of the United States served by the Midcontinent Independent System Operator (MISO).

An alternative beneficiary pays pricing option evaluates better than SPD charges

The evaluation criteria presented in the working paper assess options based on desirable characteristics, rather than expected market impacts. This approach does not seem to fit with the Authority's statutory objective, which the Authority has repeatedly stated places an emphasis on efficiency. In our view, the options should be assessed against their ability to improve dynamic and static efficiency in the electricity sector. Such criteria will better inform stakeholders of the impacts of each option and provides a consistent framework for future quantitative cost-benefit analysis.

We have carried out a qualitative assessment of four contrasting ways to implement beneficiary pays transmission pricing. A summary of the changes we would expect each option to have on market efficiency is presented in Figure ES.1. Our evaluation confirms that large or extensive efficiency gains are not achieved through transmission pricing changes. However, improvements can be made by enhancing existing incentives. We find that an area of benefit approach is more likely to generate overall efficiency gains than the SPD options examined by the Authority. This is because an area of benefit approach creates a more direct link between transmission investment decisions and transmission prices, improving future decisions on when and where to build new transmission, without distorting wholesale or retail markets.

Figure ES.1: Overview of Efficiency Impacts of Beneficiary Pays Pricing Options



The option that emerges as the best in our evaluation is not found in the working paper. This confirms that the Authority's options are too narrow, and raises the very real prospect that the Authority fails to obtain value from consulting on the working paper. We therefore recommend that the Authority issues another working paper on beneficiary pays transmission pricing that does evaluate a broader range of options against their ability to improve efficiency.

1 Introduction

As part of its review of the Transmission Pricing Methodology (TPM), the Electricity Authority (the Authority) has released a working paper that explores different options for incorporating a beneficiary pays charge into the TPM. Genesis Energy has asked Castalia to comment on the material presented in the beneficiary pays working paper. In particular, Genesis Energy wishes to understand whether the working paper has canvassed all possible options for implementing beneficiary pays transmission pricing and whether the analytical approach used to evaluate different options is robust.

We conclude that the options presented in the working paper improve significantly on the Authority's first beneficiary pays TPM proposal; the original Scheduling, Pricing and Dispatch (SPD) charge. The options presented in the working paper all result in less volatile transmission charges to market participants, and some of the options draw a closer link to transmission investment decisions.

While many of the negative effects of the SPD charge have been addressed, none of the working paper options seems to offer significant benefits. In our view, all of the options fail to meet the essential requirement of improving efficiency. Although we should not expect to see large efficiency gains from changing the allocation of transmission costs (the decisions of load and generation are not likely to be sensitive to changes in transmission prices), the Authority needs to be able to show some efficiency gains from the beneficiary pays charge.

In the remainder of this report we present a framework for identifying and evaluating beneficiary pays transmission pricing options (Section 2). We then apply this framework by:

- **Expanding the range of beneficiary pays options considered by the Authority (Section 3)**. All of the Authority's options include various applications of the SPD method, initially developed for the 2012 consultation paper '*Transmission Pricing Methodology: Issues and Proposal*'. To get the most out of the working paper consultation process, the options analysis needs to contrast the strengths and weaknesses of different beneficiary pays approaches, and
- **Evaluate how beneficiary pays options will impact on efficiency (Section 4)**. The most important factor in considering beneficiary pays options is how they impact on the efficiency of the electricity sector. While the working paper assesses options against some useful characteristics, such as simplicity, it does not evaluate possible improvements to dynamic or static efficiency. We use the same criteria to evaluate beneficiary pays options as we used in our report on the Authority's 2012 TPM proposal. These criteria consider how the charge would affect investment decisions in load, generation and transmission, and the impact of any behavioural changes in the wholesale and retail markets.

2 Conceptual Framework for Beneficiary Pays Transmission Pricing

The series of working papers on the TPM divides possible changes to transmission pricing into manageable parts so that all of the consequences of different aspects of the TPM can be thoroughly considered. To get value out of this extended TPM consultation process, the Authority needs to be open to a wide range of possible options for each component of the TPM. Instead, the beneficiary pays working paper focuses on discussing options that are all variations of the Authority's October 2012 approach to beneficiary pays transmission pricing—the SPD charge.

This section provides a framework for identifying and classifying approaches to beneficiary pays transmission pricing, and explains how these options can be evaluated by their likely impacts on efficiency. Applying this framework helps to build confidence that all of the options available for implementing a beneficiary pays charge have been considered, and that appropriate criteria are used to select which option to take forward to a comprehensive cost-benefit analysis.

2.1 Identifying Beneficiary Pays Options

To be confident that any future TPM proposal represents the best possible pricing approach, the Authority needs to identify all feasible pricing options and then develop a shortlist of options to investigate in more detail.

Identifying options that provide a range of contrasting approaches

The Authority's working paper presents beneficiary pays options that all use actual market outcomes in some way to identify the beneficiaries of transmission and calculate the price they will pay. Only the GIT-charge in the GIT-plus-SPD option applies an alternative method to a limited set of Transpower's assets (recent reliability investments).

The four beneficiary pays options presented the working paper only explore part of the range of possible beneficiary pays methods. Other approaches to applying a beneficiary pays approach include basing charges on expected market behaviour (rather than actual market outcomes) and using physical power flows on the transmission system to determine beneficiaries.

Table 2.1 presents what we see as a more complete range of beneficiary pays pricing approaches. This table categories options across two dimensions:

- Options that use an analysis of **market interactions or physical power flows**
- Options that use **revealed, actual information or forecasting models** to identify beneficiaries and set transmission prices.

The table categorises the working paper's options into these broad types of beneficiary pays pricing approach (labelled in black). With the exception of the GIT approach, the options use revealed market information to set prices. We also categorise international approaches to implementing beneficiary pays pricing (labelled in red), which all come from the United States. Despite the United States having some of the best-regarded wholesale markets in the world, none of the US approaches rely on the outcomes revealed in those markets to set transmission prices. Instead, the US approaches use either physical power flows or forecast benefits to allocate transmission costs.

Table 2.1: Approaches to Identifying Beneficiaries and Estimating Benefits

	Revealed	Forecast
Market analysis	Observed benefits received • Simplified SPD • Zonal SPD	Expected benefits • GIT-charge in GIT-plus-SPD option • MISO • NYISO
Physical flow analysis	Actual power flows • PJM	Expected power flows • MISO's former process for reliability investments

The international examples of beneficiary pays transmission pricing enable a better understanding of the possible ways to redesign New Zealand's TPM. In its October 2012 proposal, the Authority referred to FERC Order 1000, which requires Regional Transmission Organizations (RTOs) in the United States to apply a beneficiary pays philosophy. Since October 2012, RTOs have put considerable time and resources into implementing beneficiary pays transmission pricing approaches. In our view, the Authority has been remiss in issuing a working paper on beneficiary pays transmission pricing without investigating those developments.

We have reviewed beneficiary pays approaches implemented in the United States since Order 1000 for this report, and classified those approaches using the framework shown in Table 2.1. We find that the Midcontinent Independent System Operator (MISO) and the New York Independent System Operator (NYISO) use forecasts of market outcomes to model the benefits of transmission. MISO previously used expected power flows to determine the benefits of reliability investments, but no longer applies this approach. Pennsylvania-New Jersey-Maryland (PJM) Interconnection uses physical power flows to allocate transmission costs.

Exploring the high-level strengths and weaknesses of different options

The value of identifying a broader range of options is that it allows the Authority and stakeholders to debate the different strengths and weaknesses of each option. For example, the categorisation presented above enables a debate over the merits of using wholesale market outcomes to estimate transmission benefits. This deals with industry concerns on beneficiary pays pricing more directly, rather than focusing debate on the possible design features of an SPD charge.

Using a revealed benefits approach clearly has some value in identifying the actual beneficiaries of a transmission asset or group of assets. However, using observed market outcomes can create efficiency costs by changing the incentives of market participants. If a beneficiary knows that its exposure to future charges is based on its actual market behaviour, then it has an incentive to change behaviour (potentially in inefficient ways).

In contrast, market behaviour will not be influenced by transmission prices set using forecast market outcomes because charges do not depend on the actual interaction of market participants. However, forecasts rely on modelling assumptions and forecasting methods. These modelling inputs will be subject to extensive debate, and may not reflect reality as it unfolds.

2.2 Evaluating Beneficiary Pays Options

It is difficult to generate significant electricity sector efficiency improvements through transmission pricing. That reflects the fact that the impact of transmission prices on behaviour tends to be outweighed by other factors. For instance, factors such as fuel availability will more heavily influence generation investment and locational decisions. Factors such as proximity to markets will have a stronger influence over load investment and locational decisions. The role of transmission charges in allocating costs that have already been incurred (and therefore cannot be avoided) also makes efficiency gains difficult to achieve.

The link between beneficiary pays pricing and efficiency is not clear cut. Beneficiary pays pricing can best influence efficiency by enhancing existing incentives in the market. At the very least, beneficiary pays approaches should not detract from existing price signals. This suggests that the efficiency gains to be made from changing the TPM will be relatively limited when compared with the status quo.

We therefore think that a good way to structure a qualitative evaluation of different beneficiary pays options is to categorise changes based on their static and dynamic efficiency impacts compared to the status quo. We see five possible ways to generate improvements in dynamic and static efficiency (this is the same list of criteria used in our reports on the Authority's 2012 TPM proposal):

- **Providing efficient signals for load.** Beneficiary pays pricing should accurately reflect benefits to load to support the efficiency of signals to electricity consumers to invest in new equipment and consume efficiently with minimal losses to welfare.
- **Providing efficient signals for generation.** Beneficiary pays pricing should maintain the efficiency of generation investment and location decisions so the overall cost of transmission and generation is minimised.
- **Providing efficient signals for new transmission investment.** Beneficiary pays pricing should help to ensure that transmission investment is properly dimensioned, timed, and located.
- **Supporting efficiency in the wholesale market**. Beneficiary pays pricing should facilitate generator incentives to maximise their offers of capacity and ensure least cost dispatch through the wholesale market.
- **Supporting efficiency in the retail market**. Beneficiary pays pricing should help sustain competition and new entry in the retail market. It should avoid imposing inefficient costs and risks on retail market participants.

By focusing on how efficiency might change under different transmission pricing approaches, these evaluation criteria provide a consistent framework with the future quantitative cost-benefit analysis the Authority will undertake. In contrast, the working paper presents a set of criteria that are actually characteristics of the approach, which creates the risk that options preferred under the qualitative criteria do not evaluate well in a full cost-benefit analysis.

3 Beneficiary Pays Options

Having presented a framework for identifying and classifying beneficiary pays pricing options, we now describe four options that are worth evaluating in further detail.

Overview of beneficiary pays transmission pricing options

Table 3.1 outlines key design features of the four beneficiary pays options considered in this paper. These options are the simplified SPD and zonal SPD approaches presented in the Authority's working paper, as well as the "area of benefit" and "vote and pay" approaches used overseas.

Options 2a and 2b from the working paper, the "GIT-plus-SPD" and "SPD-plus-GIT", are not separately evaluated in this analysis. These options bundle a charge that is linked with the analysis carried out in the Grid Investment Test with a variation of the SPD charge. In our view, this combination of distinct options precludes an effective evaluation of the efficiency impacts of each option. Our report instead explores a charge that is linked to the analysis carried out in the transmission investment approval process through the area of benefit and vote and pay options.

In the October 2012 proposal, the Authority noted that introducing a TPM with voting rights would be difficult given the current framework for transmission investment approval.[1] While we agree that implementing a vote and pay system would have additional challenges (and would likely require changes to existing legislation), it would be premature to discount such an approach without further consideration.

Variants of the area of benefit and vote and pay approaches have been implemented in the United States in response to FERC Order 1000. These international examples are not provided to suggest that New Zealand should implement transmission charges in exactly the same way. Rather, the examples serve to illustrate how beneficiary pays transmission pricing can be implemented.

In some cases, the way we describe each option is slightly different from how it has been implemented overseas in order to better fit with New Zealand conditions. For example, we consider an area of benefit approach that periodically re-runs the same analysis carried out to inform transmission investment decisions. This is different from how the approach has been implemented in the United States, where RTOs run their economic models once to set future beneficiary pays charges. We have made this change because the Authority has emphasised that beneficiary pays options should be flexible to accommodate changes in the market over time (such as the entry or exit of participants on either the supply or demand side of the market). Even though the approach has not been implemented this way overseas, we see no reason why an area of benefit approach cannot be applied in a dynamic way by re-calculating charges from time to time.

[1] Transmission Pricing Methodology: Issues and Proposal, 2012, p. 43.

Table 3.1: Features of Beneficiary Pays Options

Options	Application to assets	Forecast or revealed benefits	Identification of beneficiaries	Calculation of transmission prices	Dynamic?	International examples
Simplified SPD	Moderate coverage ▪ Reliability and economic investments – Added between 2004-2012 with costs over $50m – Added after 2012 with costs over $20m ▪ HVDC Pole 2	Revealed	SPD or vSPD modelling using market bids and offers	▪ Charge based on gross benefits ▪ Capped at daily annualised investment cost ▪ Fixed for coming year based on last three years' wholesale market interactions (replicated in vSPD)	Yes	None
Zonal SPD	Broadest coverage (no residual) ▪ Reliability and economic ▪ All historical assets ▪ Interconnectors between zones ▪ Assets within zone	Revealed	SPD or vSPD modelling using market bids and offers	▪ Costs of investments in an interconnector charged at each node or zone based on benefit from interconnector ▪ Costs of investments in one zone are charged per load or injection within zone	Yes	None
Area of Benefit	Moderate coverage Reliability and economic investments (post-2004)	Forecast	Economic modelling using expected market behaviour and investments	▪ Cost allocated to areas of benefit based on cost savings ▪ Charge per load or injection within area	Yes	MISO
Vote and pay	Narrowest scope (largest residual) Future reliability and economic investments (post new TPM)	Forecast	Economic modelling using expected market behaviour and investments, followed by vote	▪ Beneficiaries assigned voting rights weighted by benefit allocation and vote on whether to approve the project ▪ Cost allocated to zones based on load savings ▪ Charge per load or injection within zones	No	NYISO

3.1 Simplified SPD

The simplified SPD approach essentially takes the beneficiary pays method proposed by the Authority in October 2012, and modifies it based on the concerns raised by stakeholders. In particular, the Authority has developed ways to limit the volatility of transmission prices under the SPD approach, and to better ensure that the charges reflect the benefits received by different grid users. This has largely been achieved by setting prices over a one year charging period, based on a rolling average of the estimated benefits over the last three pricing years.

This option calculates the private gross benefits of a transmission investment using a simplified model of the wholesale market clearing engine (SPD). This approach uses revealed benefits to calculate charges and then applies them in the next pricing year. While knowing transmission charges in advance aids predictability, changes in market behaviour still dictate future transmission charges, encouraging participants to alter their behaviour. On the other hand, by using actual market outcomes the simplified SPD option does adapt to market changes. Changes will affect the wholesale market clearing engine inputs, altering market outcomes, and subsequently affecting transmission prices (albeit with a lag).

We have not found any international experience with transmission pricing approaches that use anything similar to the simplified SPD option.

3.2 Zonal SPD

The zonal SPD approach is a different application of the SPD charge. This approach divides the country into zones that are linked by interconnectors, which are the transmission assets that allow electricity flow between zones.

The simplified SPD method is used to determine benefits from each interconnector to each node or zone. The net benefit to each node is the change in producer and consumer surplus from comparing the real grid scenario to one without the interconnector assets. For inter-zonal assets, beneficiaries are those nodes or zones who receive revealed net benefits from interconnector investments. If a transmission asset does not form part of an interconnector, the load and generation within the asset's zone are considered to be the beneficiaries.

While there are many examples overseas of having transmission prices that are set to reflect the costs incurred to serve sub-regions of the grid (effectively "zones"), none of those international examples use market outcomes to set transmission prices.

3.3 Area of Benefit

The area of benefit approach models market interactions to forecast the benefits that transmission assets are expected to provide at grid exit points or in particular regions. The electricity market models that are used to carry out the Grid Investment Test (GIT) are well suited to this type of analysis. Costs are then allocated to reflect the distribution of benefits that the transmission asset is expected to provide.

The GIT-based charge in the working paper's "GIT-plus-SPD" option is an area of benefit approach, but is limited to "reliability" assets approved under the GIT since 2004. An area of benefit approach can also be applied to economic investments by allocating costs based on benefits other than reductions in unserved energy. Most notably, the Investment Test estimates the benefits that arise from achieving more efficient generation dispatch and sharing generation reserves (often known as "production cost savings"). These benefits accrue to particular nodes or sub-regions within the grid, and under a beneficiary pays approach costs would be recovered from parties located at those nodes or sub-regions.

This method of beneficiary pays pricing identifies the benefits of a transmission investment by forecasting market activity, and carrying out a forward-looking assessment of the grid exit points or regions where generation or load will benefit from the grid. Beneficiaries are identified as those recipients of the positive economic benefits modelled in a multi-year analysis. The working paper identifies beneficiaries as the load at grid exit points. We see no reason the same logic cannot be applied to generators as well. The Investment Test process recognises that transmission investments can provide significant benefits to generators through increased revenues from accessing higher dispatch prices and improving output (for example by reducing hydro spill).

An area of benefit approach can be designed to reconsider the modelled benefits of parties at regular intervals. This enables beneficiary pays pricing to adapt to changing market structures over time, meeting the Authority's preference for a dynamic approach.

Unlike the options put forward by the Authority, the area of benefit approach has been applied internationally. One of the largest RTOs in the United States (MISO) provides a good case study of how an area of benefit approach can be successfully applied to economic investments (rather than restricting the approach to only apply to reliability projects). We spoke with a representative from MISO on its use of an area of benefit approach to beneficiary pays transmission pricing, and our understanding of the MISO experience is described in Box 3.1.

Box 3.1: Experience with an area of benefit approach in MISO

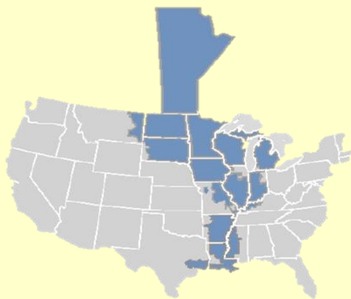
MISO is a member-based RTO responsible for transmission across all or parts of 15 US states and one Canadian province. MISO serves 42 million people and a peak demand of 130,000 MW.

FERC Order 1000 requires RTOs to incorporate beneficiary pays into transmission pricing. MISO uses a type of area of benefit approach when allocating the costs of economic investments.[2]

Projects eligible for application of this beneficiary pays charge must have:

- Positive regional economic benefits as indicated by multi-year planning
- Direct costs over $5 million—at least 50 percent of which must be associated with facilities operating at 345kV or higher, and
- A total benefit to cost ratio greater than 1.25.

Figure 3.1: Area served by MISO



Source: www.misoenergy.org

Estimating benefits and beneficiaries

Benefits are calculated as the adjusted production cost savings when comparing scenarios with and without the proposed project in the transmission system. The present value of the annual benefits is calculated for the first 20 years of a project's life from the initial service date. The modelling used to estimate benefits and beneficiaries is the same as the

2 Costs of reliability investments are charged to their local utilities. Reliability investments tend not to have broad regional beneficiaries and therefore do not require detailed modelling to identify the beneficiaries.

modelling used to approve transmission investments.

Only load customers are identified as beneficiaries of economic investments in MISO. Local Resources Zones[3] with a positive present value of annual benefits are considered beneficiaries.

Cost allocation

- 80 percent of costs are allocated amongst the Local Resource Zones that benefit:
  - Based on each beneficiary's relative benefit. This cost distribution remains fixed for the lifetime of the asset.
  - Within Local Resources Zones, costs are allocated to pricing zones based on their share of load within the area.
- 20 percent of the costs of an investment are socialised across the region through a fixed rate.

Policy considerations

Transmission owners are responsible for the financial obligations incurred while they are a member of MISO. New entrants are not responsible for paying for investments approved prior to their entry date. MISO does not regularly reset the cost allocation in order to make the approach more dynamic because such an approach would undermine the predictability of charges. Because MISO charges transmission prices to distribution utilities, there are no issues of market entry and exit (although load patterns do change).

MISO also considers issues of equity in its transmission pricing to achieve FERC's "just and reasonable" pricing standard.

Source: MISO website (www.misoenergy.org) and interview with Jeremiah Doner, MISO

3.4 Vote and Pay System

Part of the Authority's rationale in exploring a beneficiary pays approach is to improve the way that transmission investment decisions are made through the regulatory investment test process. Any incentives for beneficiaries to participate in the regulatory approvals process will be strongest if those beneficiaries get to decide which investments will proceed, and then pay for those investments. This is approach is known as a vote and pay system.

Under a vote and pay system, a regulatory investment test is run to determine that an investment will provide overall net benefits. Beneficiaries are identified by modelling economic benefits from proposed investments in the same way as the area of benefit approach. Identified beneficiaries are then assigned voting rights based on their share of the costs that they would bear under an area of benefit approach. As with any voting system, decision rules need to be developed—such as whether a simple majority is sufficient to enable a project to proceed, or whether a supermajority is needed.

The voting element of a vote and pay approach restricts its application to future projects. The vote and pay system approach therefore has limited ability to adjust to changing market circumstances. New entrants receiving benefits from an asset cannot participate in previous voting rounds, and are not required to pay for their share of benefits. Apart from this limitation, the scope of the vote and pay system is flexible and can be applied to reliability and economic investments.

[3] Local Resource Zones are defined by a range of criteria including state territories and the electrical boundaries of local balancing authorities

A vote and pay approach is used by NYISO, the RTO in New York. NYISO reserves the use of the vote and pay system for reliability projects that cost more than US$25 million. Beneficiaries are determined as the distribution utilities that have net savings in the cost of serving load in the first ten years after an asset's commissioning date. Projects need to receive 80 percent support among the beneficiaries of the project. Parties who vote against an approved project must still pay the tariff.

4 Assessment of Options

This section evaluates at a high level how the beneficiary pays options described in Section 3 evaluate against the criteria described in Section 2.2. In essence, these criteria focus on identifying beneficiary pays pricing approaches that promote:

- Dynamic efficiency gains through efficient investment decisions for load, generation and transmission services
- Static efficiency gains through wholesale and retail market opportunities.

Perhaps not surprisingly, our evaluation suggests that none of the options will deliver large efficiency gains. This reflects the reality that the primary role of transmission prices is to recover costs that have already been incurred. Nevertheless, some options perform better against these efficiency criteria than others. The area of benefit approach outperforms the SPD options because it strengthens the link between pricing and investment decisions, without creating clear opportunities to avoid transmission charges.

4.1 Providing Efficient Signals for Load

Beneficiary pays pricing should accurately reflect the benefits provided to load to the extent possible. Together with other price signals (particularly locational marginal prices for wholesale electricity), this can improve efficiency by signalling to electricity consumers when it makes sense to invest in new equipment to either increase or decrease their demand.

End-user investment decisions are unlikely to be heavily influenced by transmission charges. Instead, they are likely to be driven by characteristics such as asset location, plant size, and fuel choice. Locational price signals are already strong from the fully nodal priced wholesale energy market, which is widely considered to do a good job of signalling the cost of congestion across the transmission system. As a result, additional price signals provided by beneficiary pays pricing are likely to be small and unlikely to affect load investment decisions.

Simplified SPD

The simplified SPD charge should offer reasonably predictable charges by calculating transmission prices prior to a charging period based on a three year rolling average of estimated benefits. However, charges could change substantially in three years' time, affecting load investment decisions in assets with longer lifespans.

On balance, we do not expect the simplified SPD approach to lead to more efficient investment decisions by load.

Zonal SPD

The Authority's working paper acknowledges that within-zone charges do not necessarily reflect benefits and may therefore result in inefficient consumption. The costs of investments located within one zone are allocated at the same rate to load and generation. In reality, the benefits from transmission assets will vary amongst parties and locations. As a result, the transmission price may not reflect the benefit received.

We think this is unlikely to have a material impact on load decisions, although this will depend on the total costs recovered from within-zone charges and the amount of load contributing towards these costs.

Area of benefit

The area of benefit approach uses the estimated regional benefits of a transmission investment to signal the additional costs of providing transmission to a region. For future transmission projects, this creates a signal before an investment is made about the consequences of locating new load in a region that will need new transmission capacity. This signal could potentially lower the total cost of supplying electricity if loads locate in unconstrained areas to avoid this charge.

However, after a transmission investment has been made these efficiency gains are reversed. Having spent significant sums to put new transmission in place, the most efficient outcome is for those assets to be used. For example, the costs of the reliability investments into Auckland, NIGU and NAaN, have already been committed. The Authority's analysis seems to suggest that the Auckland and Northland regions would face higher transmission charges under an Investment Test (area of benefit) approach. However, it may well now be efficient to signal to load that it should locate in Northland, despite the transmission costs. The alternative is to have spare capacity on transmission lines lying idle.

The area of benefit approach would generate more stable and predictable price signals because benefits are calculated on a forward looking basis, rather than relying on market behaviour. This stability reduces incentives for load to change behaviour. However, the process of resetting prices at periodic intervals would provide some incentive for load to monitor any changes in the benefits provided by the transmission grid, and factor those benefits into their decisions.

Any approach that uses forward-looking models runs the risk that grid users do not actually receive the predicted benefits, and therefore pay charges that are higher than the value they receive. This can cause inefficient reductions in consumption, creating deadweight losses. However, these risks can be limited through the design of the beneficiary pays charge. For example, by only recovering a proportion of an asset's cost through the beneficiary pays charge (such as 80 percent of the cost in MISO), the Authority could have greater confidence that any errors in estimated benefits do not cause inefficient reductions in consumption. Additionally, regular re-assessments of the modelling can ensure that forecast benefits keep in reasonable alignment with actual benefits.

Vote and pay

A vote and pay approach provides signals to load before an investment decision is made. The increased participation in approving transmission investments helps to offset the uncertainty of allocating charges without knowing how sensitive loads are to changing transmission prices.

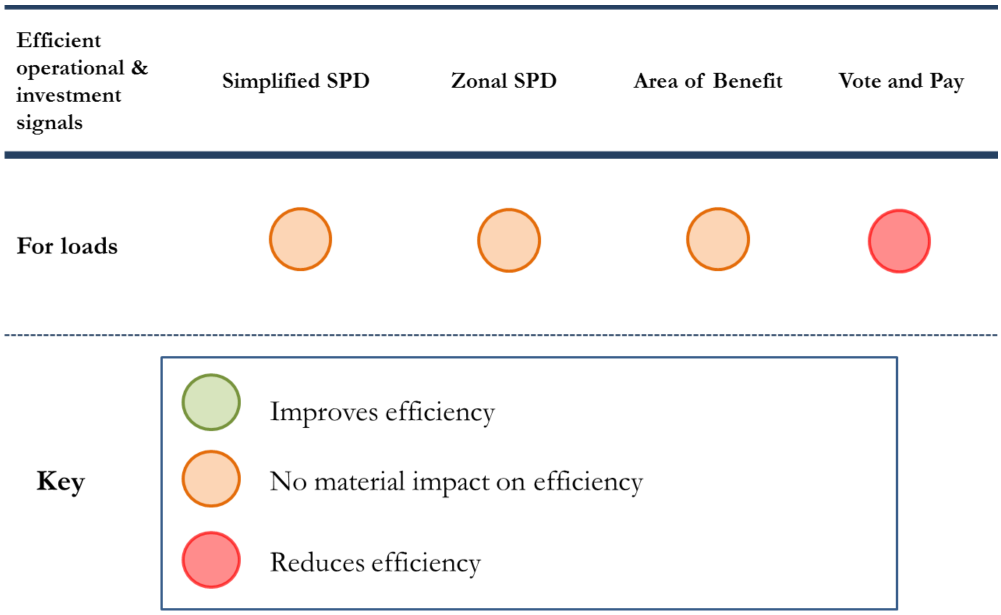
Vote and pay uses modelled benefits and there is the risk that users' benefits may be smaller than transmission prices. Parties who vote in opposition to new transmission investments may not recognise their allocated private benefits but would be required to pay for them nonetheless. This risk can be limited through policy design as described above and by having a high vote threshold for approving projects.

Ultimately, however, vote and pay has no ability to adapt to changing market circumstances or the distribution of benefits. Transmission cost allocations can become out-dated, reducing the efficiency of locational and investment signals to load. In essence, this risks locking in high transmission prices based on a future that did not eventuate—rather than adjusting prices based on how benefits have actually been realised.

Summary of efficient signals for load

Our analysis of the beneficiary pays pricing approaches in providing efficient signals for load is summarised in Figure 4.1. Overall, we conclude that transmission prices are not a determining factor in most load investment and locational decisions, which limits the impact of transmission pricing on efficiency. Gains in efficiency are typically reversed due to the lumpy nature of transmission investments. However, we do consider that signals to load can become inefficient under a vote and pay system because charges cannot adapt to changing market circumstances and the distribution of benefits.

Figure 4.1: Efficiency Impacts for load



4.2 Providing Efficient Signals for Generation

Beneficiary pays pricing should maintain the efficiency of generation investment and location decisions so that the overall cost of transmission and generation is minimised.

Similar to load, decisions to invest in new generation may not be heavily influenced by transmission costs. Factors such as fuel costs, fuel availability and resource consents are likely to have a stronger influence on where new generation is built (unless the cost allocation approach is particularly direct, such as the current HVDC charge). Additionally, nodal pricing already provides strong signals on the cost of congestion. Any improved locational signalling through transmission pricing is likely to bring small efficiency gains because the locational signals will be an order of magnitude less than those in the wholesale energy market.

Simplified SPD

The simplified SPD approach appears to do little to signal the value of available transmission capacity to generators. From our analysis of the SPD files published by Authority, the generation share of the simplified SPD charge accounts for 20 percent or less of the total beneficiary pays charges recovered from all of the major generator-retailers, except Meridian Energy. It is unclear whether the sums involved would be sufficient to change a generator's decisions on where to locate and how to operate.

The inability to recover all costs through the simplified SPD charge also creates the need for a residual charge. The application of a residual charge, depending on its design, is also unlikely to improve the investment decisions of new generators. Indeed, this raises the risk that beneficiaries may not value the benefits they are paying for through the combined application of a beneficiary pays charge and the residual charge, which may lead to an inefficient reduction of grid usage.

Zonal SPD

The zonal SPD approach allocates a greater share of the costs of transmission to generation. The generation share of the zonal SPD charge accounts for 30-50 percent of the total beneficiary pays charges recovered from all of the major generator-retailers, except Trustpower.

However, the aggregation of benefits in the zonal approach appears to obscure transmission price signals to generation because private benefits are not necessarily reflected in charges. Generators can be allocated transmission costs that outweigh the benefits they are receiving. Their use of transmission may therefore reduce below inefficient levels as a result.

Area of benefit

The area of benefit approach provides locational signals to generators that locate in the area of benefit. These signals are provided in the same way as in the original investment approval process, enabling generators to better forecast changing transmission prices and incorporate those price forecasts into their investment and operating decisions. This approach still does not overcome the challenge of signalling available capacity on the grid after costs have been committed, which may discourage efficient use of the grid.

Inaccurate modelling assumptions would have negative effects on locational and operational decisions if generators pay more or less than the benefits they actually receive. However, this risk can be limited by recovering less than the full costs of each transmission asset through the beneficiary pays charge. Regular re-assessments of the modelled benefits can also improve the accuracy of forecasts by calibrating expected benefits with realised benefits over time.

Vote and pay

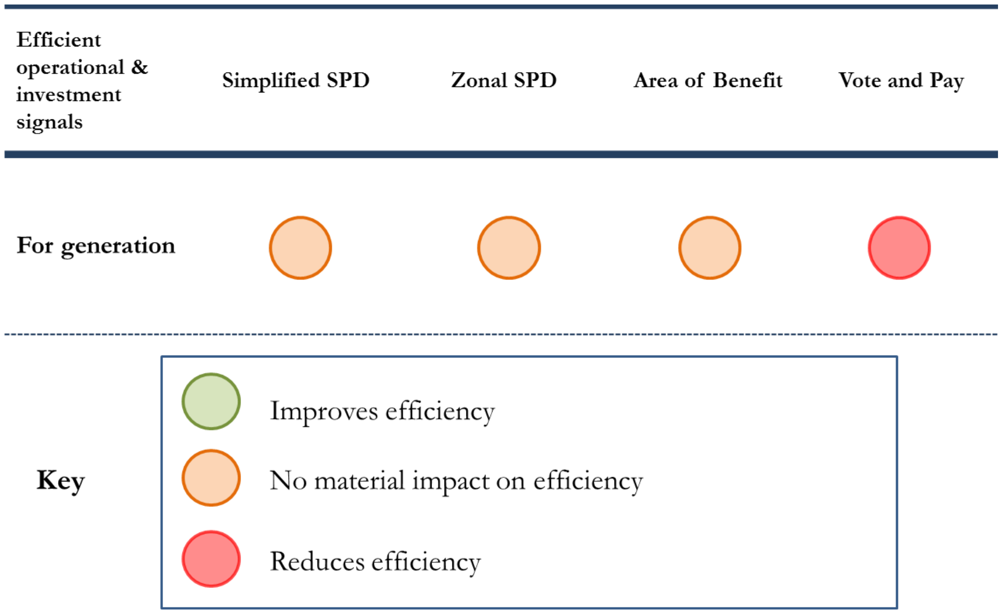
The vote and pay system is an effective way to validate that the benefits estimated in a regulatory test align with participant's expectations of the benefits they will receive. Voting therefore helps to prevent the risk that transmission prices outweigh the benefits received, although this is limited by tag along rights that force parties that do not support the investment to pay. The allocation of costs is determined before an investment is approved, giving generators and developers time to factor the transmission charges into their future decisions.

Despite these benefits of a vote and pay system, this approach is not able to deal with markets changes over time, which could reduce the efficiency of signals to generation. Only those generators in the market at the time of the investment approval process can support the modelled benefits and contribute to the transmission investment. However, generators may enter or exit the market over the lifetime of the transmission asset. As cost allocations become out-dated, the efficiency of locational and investment signals to generation is likely to reduce.

Summary of efficient signals for generation

Our analysis of the beneficiary pays pricing approaches in providing efficient operational, investment, and locational signals for generation is summarised in Figure 4.2. The efficiency gains from the approaches are limited because generation decisions are unlikely to be driven by any of transmission prices considered in this paper. Signals to generation become inefficient under the vote and pay system because it cannot adapt to changing market participants and benefit distributions.

Figure 4.2: Efficiency Impacts for Generation



4.3 Providing Efficient Signals for New Transmission Investment

Beneficiary pays pricing should help to ensure that transmission investment is properly dimensioned, timed, and located. The Authority is clearly keen to improve outcomes in this area, and has commented on several occasions that the decisions made under the current regulatory approval process may not be optimal. Improving those decisions requires a link between a TPM and the Investment Test.

Simplified SPD

There is no interaction between the determination of the SPD charge and Investment Test approval process under the simplified SPD approach. The approval of a transmission project requires forecast benefits to outweigh project costs, while simplified SPD charges are determined later by actual market outcomes. This means that participation and disclosure of information into the regulatory approvals process will not affect the charges facing beneficiaries.

The Authority believes that parties will be more likely to participate in the investment approval process simply because they will be charged according to the estimated benefit they receive. However, we fail to understand this logic. At the extreme, if charges exactly match private benefits then participants become indifferent as to whether or not a particular project proceeds. If the Authority addresses this concern by designing the SPD charge in a way that provides confidence that parties will always pay less than their private benefits (for example by capping estimated benefits over some time period), then it is hard to see why parties would oppose any proposed investments.

Participants may well have a range of reasons for not revealing all relevant information to the regulator making transmission investment approval decisions, such as commercial confidentiality or differing views on risk. We therefore conclude that this approach does not result in any changes in efficiency around transmission investment.

Zonal SPD

As for the simplified SPD approach, there is no interaction between applying the zonal SPD charge and the Investment Test approval process. For the same reasons, we conclude that this approach is not likely to change the efficiency of transmission investment decisions.

Area of benefit

The area of benefit approach has a direct link with the investment approval process because the same analysis used in the Investment Test would be used to set transmission prices. This creates a strong incentive for participants to understand the suite of models used in the Investment Test process, and to ensure that Transpower and the Commerce Commission have all the information needed to run those models.

Parties that are modelled to receive significant benefits will have an incentive to question the justification for the investment provided that they disagree with the modelling. If the modelling results would be improved with further information, then those participants would have an incentive to provide that information. Parties without significant benefits will likely have little incentives to participate in the process.

In Box 4.1 we describe one transmission investment that we think highlights the strength of this approach—the Clutha Upper Waitaki Lines Project (CUWLP), referred to in the Authority's working paper as the Lower South Island Renewables investment. This project has been approved as an economic investment, but has not yet been carried out by Transpower.

Box 4.1: Applying an Area of Benefit Approach to the Clutha Upper Waitaki Lines Project

The Clutha Upper Waitaki Lines Project (CUWLP) is an economic investment expected to cost around $200 million. The project includes upgrading transmission lines to transport electricity north from generators located in the lower South Island. The project was originally designed to transport electricity generated from wind farms slated for development in the lower South Island (Project Hayes being the largest proposed wind farm). These projects have recently been cancelled. However, the potential closure of the Tiwai Point aluminium smelter means that the upgrade may still have economic value in transporting electricity north from existing generators that currently supply the smelter.

The combined effect of the existing transmission investment approval process and TPM does not provide the right incentives to generators that would benefit from the CUWLP to accurately portray the benefits they would receive. If all costs are recovered through interconnection charges, then these generators have strong incentives to claim that the project provides net benefits to the electricity sector and should therefore be built. In contrast, the Tiwai point aluminium smelter has strong incentives to claim that it has no immediate prospect of closing, and so the project does not offer net market benefits.

Aligning estimated benefits and transmission prices

An area of benefit approach would establish prices for the transmission investment that reflect benefits determined through the Investment Test process. Most of the benefit would be received by generators located south of the constraint that would occur if the Tiwai Point aluminium smelter closes. The upgrade enables these generators to access higher prices for their output than would otherwise exist in an over-supplied market in the lower South Island. Transmission prices would be based on changes in the producer surplus earned by these generators.

Consumers would also be affected by the CUWLP project. The increased dispatch of low cost renewable generation might mean that consumers north of the new transmission asset avoid the capital costs of building new generation in other areas to meet future demand. These benefits would also be reflected in prices under an area of benefit approach. In contrast, the Tiwai Point aluminium smelter would pay higher electricity prices if the CUWLP project goes ahead because surplus generation in the lower South Island will be transported north.

Why this improves information disclosure for investment approvals

The economics of the CUWLP upgrade depend on whether the Tiwai Point smelter closes. Apart from the smelter's owners, the party with the best information on the probability of closure is likely to be Meridian Energy (as a contractual counterparty to the smelter). The Investment Test can forecast whether CUWLP provides net benefits under different scenarios, and investment decisions can be based on some weighting of the likelihood of those scenarios. However, linking those decisions to who pays improves incentives because:

- If the Investment Test overstates the true probability of the smelter closing, then generators would reveal why that is the case in order to decrease their transmission charges
- If the Investment Test understates the true probability of the smelter closing, then generators would reveal why that is the case in order to ensure that the investment is approved.

These incentives remain far from perfect. For example, as long as the forecasts estimate net benefits from the project, then generators will not have incentives to reveal information that the probability of the smelter closing is actually higher than assumed. Nevertheless, setting transmission prices in the areas that benefit from the investment better aligns incentives when compared with the status quo.

Re-assessing benefits at regular intervals slightly weakens the incentives to participate in the initial investment approval process because parties know that their allocation of costs will be reconsidered at a future time. However, the area of benefit option provides stronger incentives to participate in the process than charges based on actual market outcomes because price resets will use the same modelling approach and assumptions. This approach provides a more direct link between investment approvals and pricing, meaning that parties that support an investment will pay, while parties that oppose an investment will likely have valuable new information to bring to the process.

Vote and pay

The vote and pay approach has the strongest link with the transmission investment approval process. This approach determines benefits and beneficiaries prior to an investment being approved, effectively requiring grid users to pay for those new transmission assets that they want built.

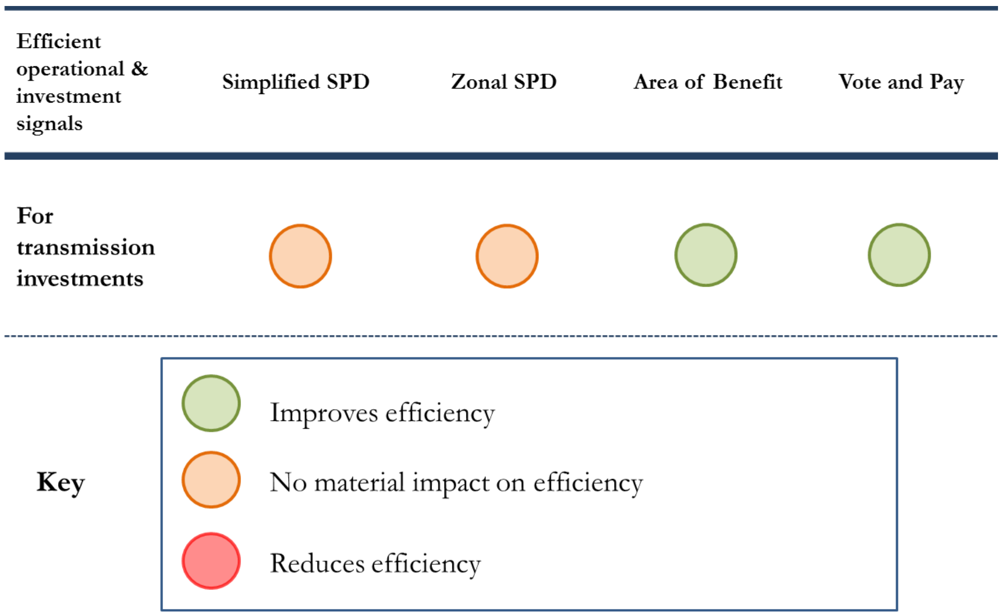
The voting process creates strong incentives to participate in transmission investment approval because identified beneficiaries may not agree with their allocated costs. Under a vote and pay system, these parties still have an opportunity to avoid these costs if they prevent supportive votes from reaching the determined threshold. In this way, a vote and pay system improves the decision-making process as beneficiaries reveal their preferences in the voting process, while at the same time supplying more information into the process.

A vote and pay system would require rules to ensure that those involved in voting for or against a project are actually the long-term beneficiaries. Without rules around the market entry and exit of beneficiaries, the costs of transmission investments may only be partially-recovered or new beneficiaries of a past investment may not be held responsible for its costs. These situations undermine the efficiency of transmission investment decisions.

Summary of efficient signals for new transmission investment

Our analysis of the beneficiary pays pricing approaches in providing efficient signals for new transmission investment is summarised in Figure 4.3. Despite the Authority's focus on improving transmission investment efficiency, neither the simplified nor zonal SPD methods generate strong incentives for greater participation. Determining beneficiaries prior to investment approval creates an explicit incentive for parties to actively participate in the process as they know their individual expected charges.

Figure 4.3: Efficiency Impacts for New Transmission Investment



4.4 Providing Efficient Signals in Wholesale Markets

Beneficiary pays pricing should facilitate generator incentives to maximise their offers of capacity and ensure least cost dispatch through the wholesale market.

Simplified SPD

While a number of positive changes have been made to the SPD approach since October 2012, the simplified SPD approach does not address the concern that using market outcomes to allocate transmission costs provides an incentive for generators to change their offers. Several submissions on the October 2012 proposal convincingly showed that with an SPD charge, generators could alter their infra-marginal and super-marginal offers to avoid transmission costs.

Extending the assessment period over three years will reduce this incentive because the benefits of strategic bidding will take time to materialise. However, we see no reason for this time lag to deter attempts by generators to alter their offers to increase their profits. This reduces efficiency because when generators get their offer strategies wrong this causes inefficient dispatch in the wholesale market, eventually raising prices.

Zonal SPD

Incentives to inefficiently change generator offer behaviour also exist under the zonal SPD approach. In this case, market interactions are used to determine the benefits provided by interconnectors between zones. The risk of strategic bidding could be limited by defining the transmission grid in a way that creates less benefit to generators in altering their offers. However, this cannot ensure that inefficient changes in offer capacities will be deterred altogether.

Area of benefit

An area of benefit approach does not use generator offers to set transmission prices. Instead, transmission prices are set using forward-looking models that use assumptions on how generators offer in their capacity to the market (typically that offers reflect the short run marginal cost of operating each generating unit). The separation of transmission prices and market outcomes means that generators have no incentives to change their offers because doing so would not change their transmission charges.

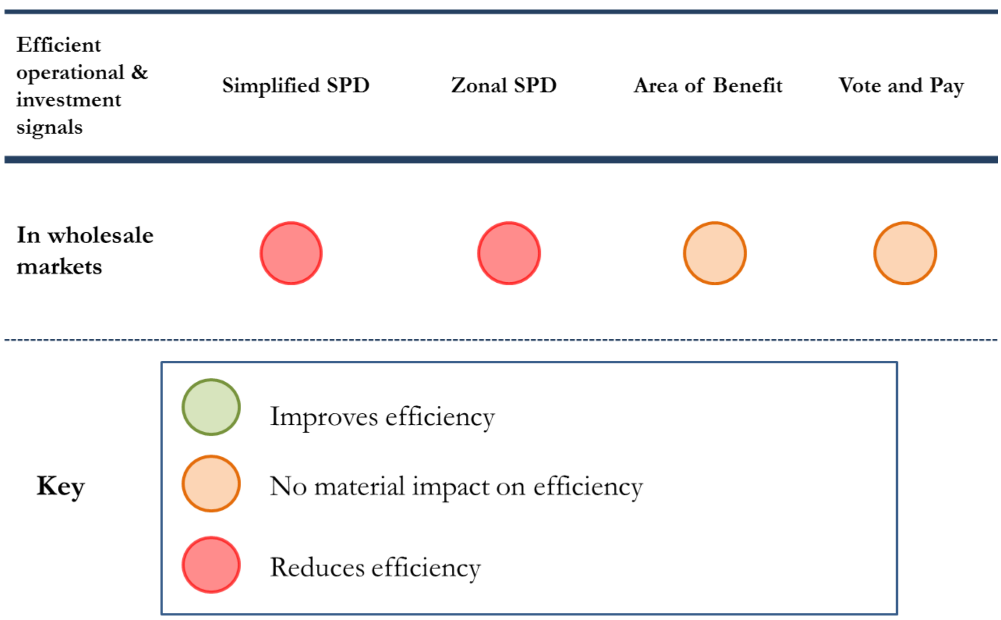
Vote and pay

For the same reasons as an area of benefit approach, under a vote and pay system generators face no incentives to change their wholesale market offers.

Summary of efficient signals for the wholesale market

Our analysis of the beneficiary pays pricing approaches in contributing to wholesale market efficiency is summarised in Figure 4.4. The simplified SPD and zonal SPD options create an incentive for generators to alter their market offers, threatening efficient dispatch. In contrast, by de-linking transmission prices and market outcomes, the area of benefit and vote and pay approaches pose no threat to efficient dispatch (while not materially increasing market efficiency either).

Figure 4.4: Efficiency Impacts in Wholesale Markets



4.5 Providing Efficient Signals in Retail Markets

Beneficiary pays pricing should help sustain competition and new entry in the retail market. The approach should therefore avoid imposing inefficient costs and risks on retail market participants.

Simplified SPD

The Authority has made considerable improvements from the October 2012 proposal in addressing the volatility of SPD charges. The greater stability implied by the charge reduces the risk that retailers are forced to maintain higher levels of cash in reserves to cover high monthly transmission bills. An annual charging period also better matches the timeframe that retailers set their prices to their customers, providing greater certainty of cost-recovery.

However, we continue to see no observable efficiency gains from charging retailers directly for transmission instead of distributors. Indeed, much of the need for transmission charges that respond to changing market circumstances disappears if distributors are charged for transmission. Distributors are an essential part of the physical supply chain, and therefore have a degree of permanence that retailers can never achieve (even the large retailers could exit the market). For this reason, even in parts of the United States that have retail competition, distribution utilities are still charged for transmission.

Zonal SPD

The working paper states that inter-zonal charges are likely to be applied to retailers rather than distributors. As with the simplified SPD approach, we see no efficiency gain arising from this preference.

The working paper has not established a definite means of charging transmission costs for within-zone charges. However, it suggests a per-MWh charge for positive net injections and net offtakes. This approach should help to reduce the uncertainty of passing through transmission charges to loads.

Area of benefit

This approach involves no change to retail market efficiency because the costs allocated to load are charged to distribution companies. Retailers then compete on a level playing field to minimise the other costs of serving end consumers.

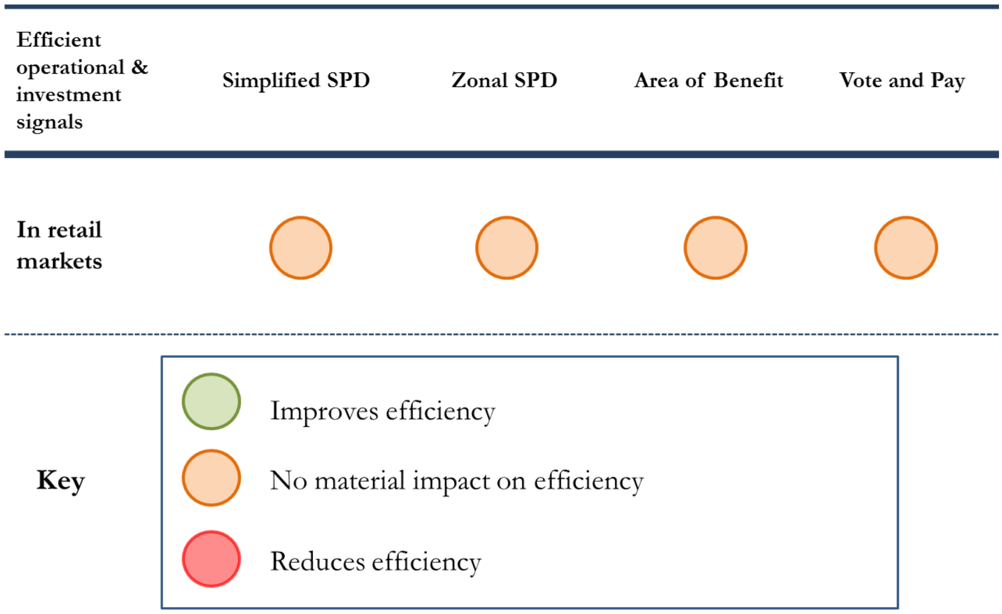
Vote and pay

This approach involves no change to retail market efficiency because the costs allocated to load are charged to distribution companies. Retailers then compete on a level playing field to minimise the other costs of serving end consumers.

Summary of efficient signals for the retail market

Our analysis of the beneficiary pays pricing approaches in contributing to retail market efficiency is summarised in Figure 4.5. None of the options create significant retail market efficiencies. In our assessment, the decision on whether to charge retailers or distributors does not impact efficiency in the retail market but seems to be a design choice that has no advantages.

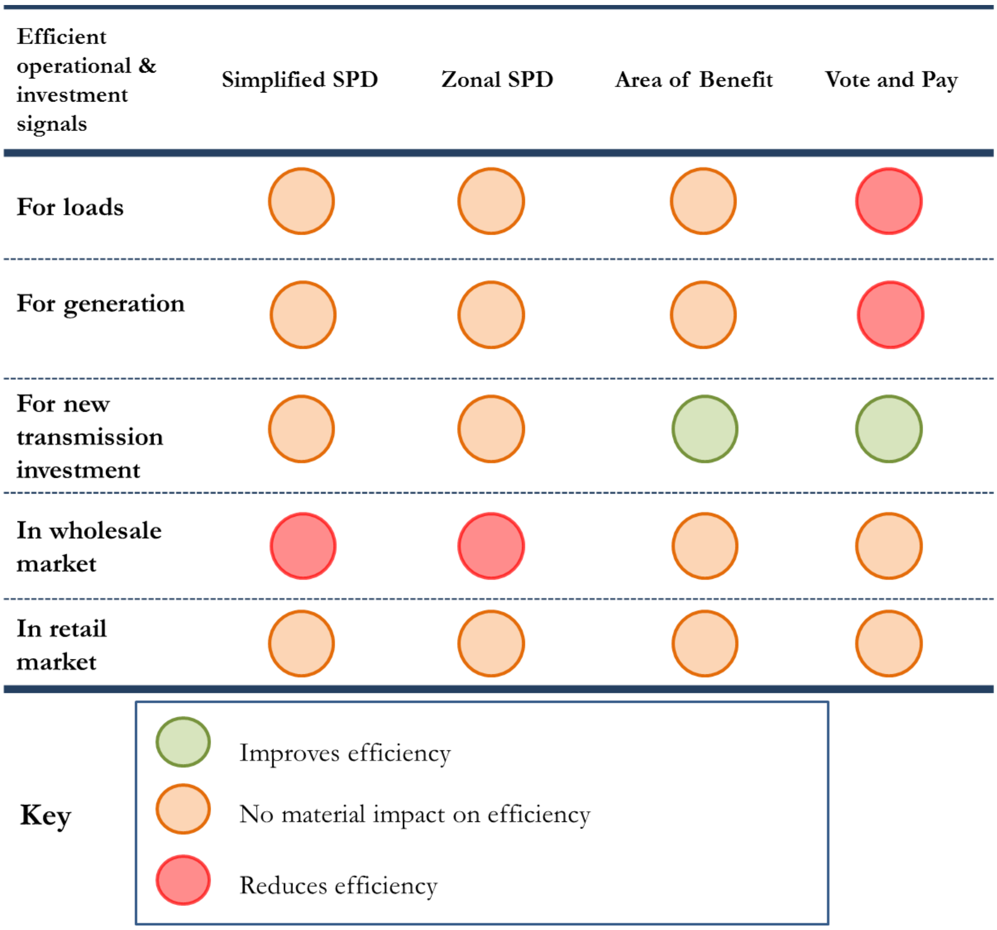
Figure 4.5: Efficiency Impacts in Retail Markets



5 Conclusion and Recommendations

Figure 5.1 summarises our evaluation of how the four beneficiary pays options presented in this paper are likely to change efficiency. We find that none of the options generates overwhelming efficiency gains across the electricity supply chain. This result is not surprising given the relatively limited impact that transmission prices generally have on market participants' future decisions. Overall, we conclude that the area of benefit approach is the only option likely to deliver net benefits. These benefits would arise from creating a more direct link between transmission investment decisions and transmission prices, improving future decisions on when and where to build new transmission.

Figure 5.1: Summary of Efficiency Impacts



Despite emerging as the best option in this evaluation, the area of benefit approach is not considered in the Authority's working paper. This validates concerns the beneficiary pays options presented to the industry have been narrowed too much, too early in the consultation process. By tweaking the application of the SPD charge rather than considering true alternatives, the working paper is unlikely to allay industry concerns over beneficiary pays approaches or improve understanding of how such pricing approaches might be designed.

We recommend that the Authority issues another working paper on beneficiary pays approaches. While this would further extend an already long process, this would ensure that the full range of options is presented, and that any future TPM proposals are informed by a constructive consultation process.

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