GAS INDUSTRY COMPANY LIMITED

Allocation and Reconciliation in Overseas Gas Markets

Final Report

May 2006

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Scope and Structure of this Report

Scope

- review overseas gas markets of similar scope, structure and style to NZ market
- describe the arrangements for determining gas quantities for customers and shippers, before and after the gas day
- define how these gas quantities are used in the calculation of balancing and transport charges

Structure

A. Background
B. Forecasting
C. Trading
D. Initial Downstream Allocation
E. Final Downstream Allocation
F. Upstream Allocation
G. Charging
H. Conclusions

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This report presents the findings of a review of international gas markets to understand the different methods used to determine gas quantities attributable to each shipper or retailer using a transmission or distribution pipeline.

Whilst the report covers both upstream and downstream quantities for all sizes of shipper or customer, the focus is on the small customer who will not have daily metering and whose period meter will not be read until a considerable time after the gas day.

Markets typically require quantities to be determined in three timescales:

- *forecasting*: usually the day prior to the gas day (D-1), required for nominating and scheduling;
- *initial allocation*: usually between D+1 and D+7, required for an early assessment of shipper imbalances so that these can be rectified; and
- *final allocation*: anywhere from a month to a year after the gas day, when period meters have been read and gas quantities can be estimated with more accuracy, required for final settlement of gas imbalances and transportation charges.

Knowing the way in which these various quantities are used is important in understanding why a particular method has been chosen. Typically, in any method, there is a trade-off between timeliness, accuracy and cost. Thus, the use to which a determined quantity is put will affect the relative priority assigned to these competing objectives.

For comparison, methods used in the NZ gas market are also presented. Differences between the NZ and international approaches – and the possible reasons why these have arisen and should or should not continue – are discussed in the “conclusions” section.

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Terminology used in this report

Term	Meaning
Allocation Agent	A person contracted by shippers to undertake an allocation process
Average Price	The average clearing price in a gas spot market over a gas day
Downstream Allocation	Allocation of gas between shippers at a delivery point out of a transmission pipeline
Entry Point	The point at which a producer is connected to a pipeline
Final Allocation	Downstream Allocation occurring following non-daily meter reads
First Tier Customer	Customer supplied by a designated "host" retailer: usually the incumbent
Initial Allocation	Downstream Allocation occurring following daily meter reads but before non-daily meter reads
Input (Offtake)	Deliver gas into (receive gas out of) a pipeline
Interconnection Point	The point at which two transmission pipelines interconnect
Marginal Price	The highest or lowest clearing price in a gas spot market over a gas day
Market Operator	The person responsible for determining balancing charges
Mismatch	The difference, for a shipper, between total receipt and delivery quantities on a pipeline
Pipeline Operator	The person responsible for operating a transmission pipeline
Reconciliation	Accounting for differences in quantities or charges between initial and final allocations
Retailer	A shipper supplying customers connected to a distribution network
Second Tier Customer	Customer not supplied by the host retailer
Shipper	A person transporting gas on a transmission pipeline
Upstream Allocation	Allocation of gas between shippers at a receipt point into a transmission pipeline
Variance	The difference, for a shipper, between forecast and allocated quantities at a point

The markets reviewed use a variety of terminology. To avoid confusion, this report applies a common terminology which therefore, of course, may be different to that used by a particular market.

In particular, the report terminology differs from that used in the NZ market in the following areas:

- the terms "upstream allocation" and "downstream allocation" mean allocation at receipt and delivery points on the Vector pipeline system, respectively. The NZ market uses the term "allocation" but is less clear on the meaning of "upstream" and "downstream" ;
- the term "reconciliation" means accounting for differences between initial and final allocations. The NZ market uses this term to mean an annual "wash-up" process.
- "input points", "interconnection points" and "offtake points" mean points where a producer, another pipeline or a distribution network connects to a transmission pipeline, respectively. The NZ market would use the terms "receipt point", "receipt point" and "delivery point" (from a transmission perspective), respectively.

Acronyms used in this Report

Acronym	Meaning
AA	Allocation Agent
AP	Average (spot) gas price
AQ	Annual Quantity
D+x	x business days after gas day
DB	Distribution Business
DM	Daily Metered
DQ	Daily Quantity
FOD	Flow-on-Delivery
FON	Flow on nomination
FPN	Flow in proportion to nomination
GSL	Gross system load
HDD	Heating degree days
ICP	interconnection point

Acronym	Meaning
M+x	x business days after end of gas month
MDA	metering data agent
MDQ	Maximum Daily Quantity
MM	Mismatch
MO	Market Operator
MP	Marginal (spot) gas price
NDM	Non-daily Metered
NSL	Net system load
P/L	Pipeline
P2P	Point-to-point
PO	Pipeline Operator
ST	Short Term
UFG	unaccounted for gas

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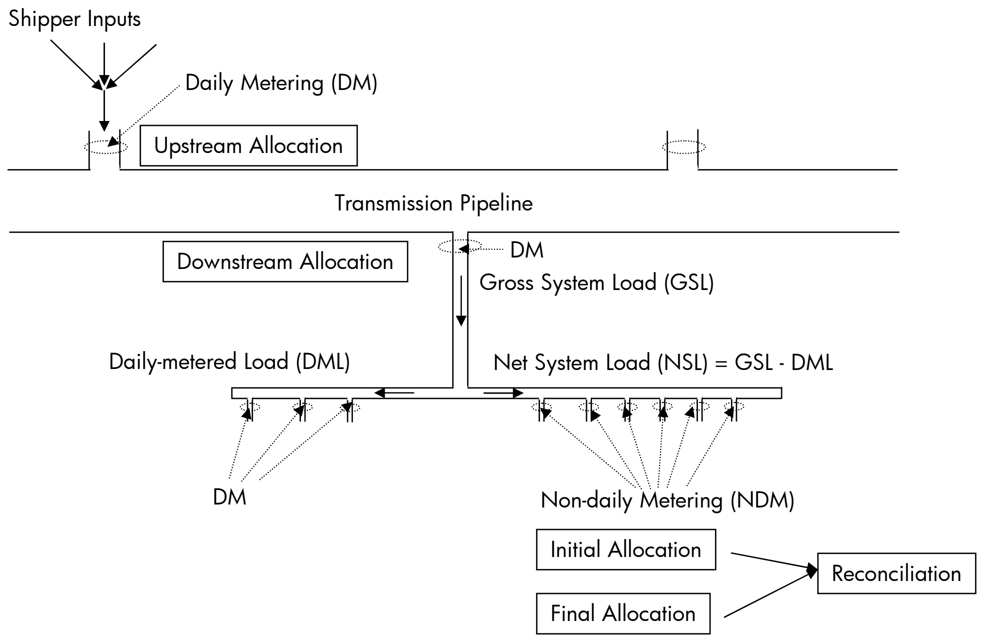
Generic Metering Topology



Physically, all gas markets are broadly similar. Producers "input" gas into a high pressure transmission pipeline or pipeline network. Gas is then taken off at "offtake points" and delivered into a distribution network. From this network, gas is delivered to individual customers.

Of course, large customers may offtake directly from transmission, but allocation for these customers is straightforward, and so these are not considered further in this report.

Thus, there are three points where a "custody transfer" (ie a change in the entity transporting the gas) or "title transfer" (ie a change in the entity shipping the gas) may take place. At each of these three points, gas quantities for each shipper, retailer or customer must be determined. In this report, these quantities are referred to as follows:

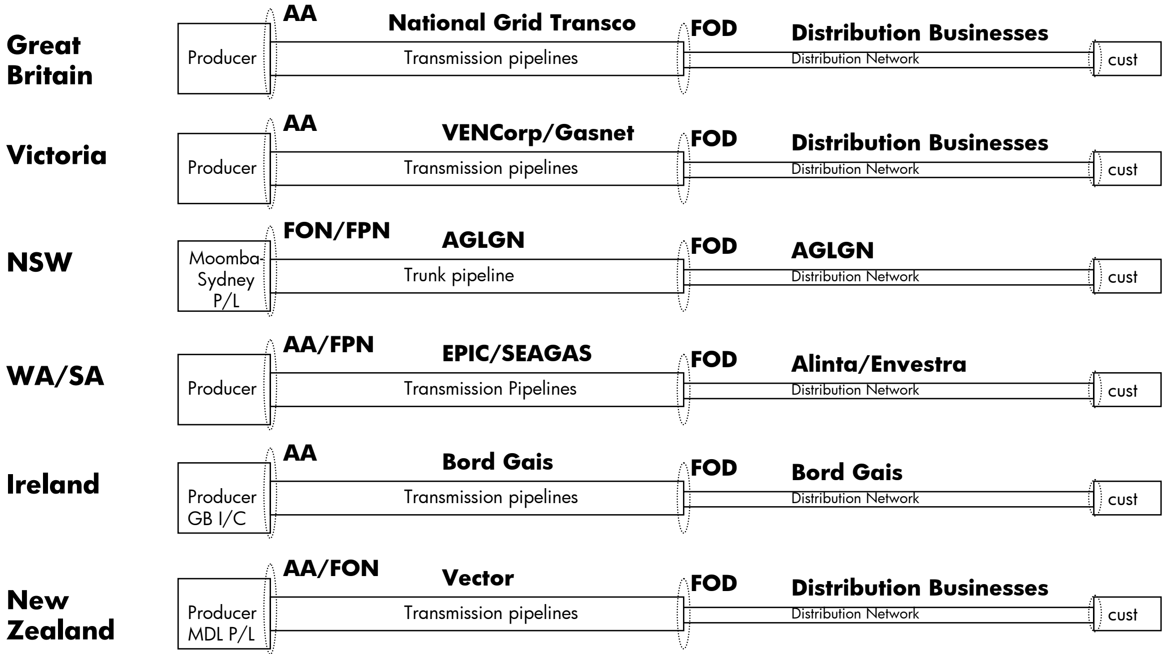
- at the producer-transmission interconnection: the upstream allocation
- at the transmission-distribution interconnection: the downstream allocation
- at the distribution-customer interconnection: the customer quantity

These quantities will be used in determining shipper and customer charges for gas, transportation and balancing levied by producers, pipeline owners and distributors.

Whilst different terminologies are used, several of the markets rely on the calculation of a quantity called (in this report) the net system load (NSL). This is the quantity metered at one or more offtake points (the gross system load (GSL)) minus the total daily-metered quantities of customers downstream of the offtake point(s).

SECTION A: BACKGROUND FINAL

Markets Reviewed: Physical Overview



Allocation Methods

AA = allocation agreement: all gas allocated according to agreement between shippers
FON = flow-on-nomination: allocation=nomination, variance allocated to operational imbalance
FPN = flow proportional to nomination: variance shared between shippers in proportion to nomination
FOD = flow-on-delivery: allocation equals aggregate quantity delivered to customers (residual to linepack or UFG)

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Five overseas markets have been reviewed: two from the British Isles (Great Britain and Ireland) and three from Australia (Victoria, NSW and WA/SA). The WA and SA markets are treated together since, although they are geographically quite separate, they operate under (largely) common market rules and a single market operator.

Whilst each market has the producer-transmission-distribution-customer physical supply chain described in the previous slide, NSW is slightly different in that (like NZ) it has a main transmission pipeline (Moomba-Sydney) feeding into a smaller pipeline (the Wollongong-Wilton-Newcastle "trunk" pipeline) which then feeds the distribution networks. To maintain comparability, only the downstream transmission pipeline is reviewed and this is compared to arrangements on the Vector pipeline system in NZ. Allocation on the MDL pipeline is not considered as this is based on flow-on-nomination and so not related to customer quantities.

A common feature of all of these markets is that downstream allocation is based on a "flow-on-delivery" approach. That is, for a particular shipper/retailer, it is deemed equal to the aggregate customer quantities of all customers downstream of that interconnection, plus allowance for UFG. Thus, the downstream allocation method really refers to the method for determining, and aggregating, these customer quantities. Various methods are used, however, for upstream allocation.

The markets vary in other ways. For example, in NSW and WA/SA, more than one transmission pipeline can feed a single distribution network and so allocation becomes more complex. Also, in SA and Victoria, sub-daily (eg hourly) quantities must be determined. As these concerns are not relevant to NZ, methods used for dealing with them are not presented in this report.

Markets Reviewed: Commercial Overview

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Market Operator (MO)	Transco	VENCorp	GMCo	REMCo	Bord Gais	Vector
Pipeline Operator (PO)	Transco	VENCorp	AGLGN	EPIC	Bord Gais	Vector
Distributor Owner (DB)	various	various	AGLGN	SA:EnvestraWA: Alinta	Bord Gais	Various
Market Annual Consumption (PJ)(c)	3360	251	142	SA=135 WA=369	152	200
Retail Annual Consumption(c)	1244(a)	133	31	SA=35 WA=37	13(b)	40
Retail Contestability	Full	Full	Full	Full	>18TJ/yr	Full
Retail Customers (000s)	20,000	1500	900	SA=345 WA=458	428	250

a) includes Northern Ireland (ie relates to the entire United Kingdom rather than just Great Britain)
b) excludes Northern Ireland (ie relates to Eire only)
c) The amounts quoted use a variety of sources, years and definitions and so should be treated as indicative rather than authoritative

The commercial characteristics of markets are also important in understanding different approaches to determining and using gas quantities. Apart from Great Britain, which is an order of magnitude larger, all of the markets reviewed are broadly similar in size to NZ. And, apart from Ireland, all the markets – like NZ – have "full" retail contestability (ie covering all customers) and have done for some time.

Of course, retail contestability brings another set of problems, associated with tracking the changing retailer-customer relationships. Indeed, downstream allocation can be seen as constituting four steps:

- determining customer quantities;
- determining which retailer serves each customer;
- aggregating customer quantities separately for each retailer; and
- incorporating each retailer's share of UFG, if any.

Processes involved in the second step would include customer registration and transfer. These are outside the scope of this report.

In each market, there are – of course – entities responsible for managing the operation of the transmission and distribution pipelines. There must also be a third entity – termed the "market operator" here – responsible for ensuring that the various allocation processes are undertaken and the relevant balancing charges are calculated and invoiced. In some markets, two or three of these entities may come under the same corporate entity, but will nevertheless remain separate business functions within that corporation.

Markets Reviewed: Governance Overview

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Legal Power	Licence Contract(f)	Statute	Licence(a)	Licence(a)	Licence Contract(f)	TSA
Rule Change Decision	Voting Panel	MO	MO	Voting Panel MO	stakeholder forum	NAG(m)
Rule Change Approval	regulator	regulator	MO	WA: Minister SA: Regulator	regulator	not formally specified(n)
Enforcement	not specified(j)	MO	Compliance Panel(b)	Compliance Panel(b)	PO	not specified
Accreditation	none	Retailers(d)	MDAs(e)	All	New Shippers	none
Dispute Resolution	Expert(i) Mediation	Adviser, Panel(c)	Panel(g) MDA	Compliance Panel	Regulator	NAG(m)
External Audit	on NDM reconciliation	annual	annual(h)	annual(l)	none specified	on retailer request

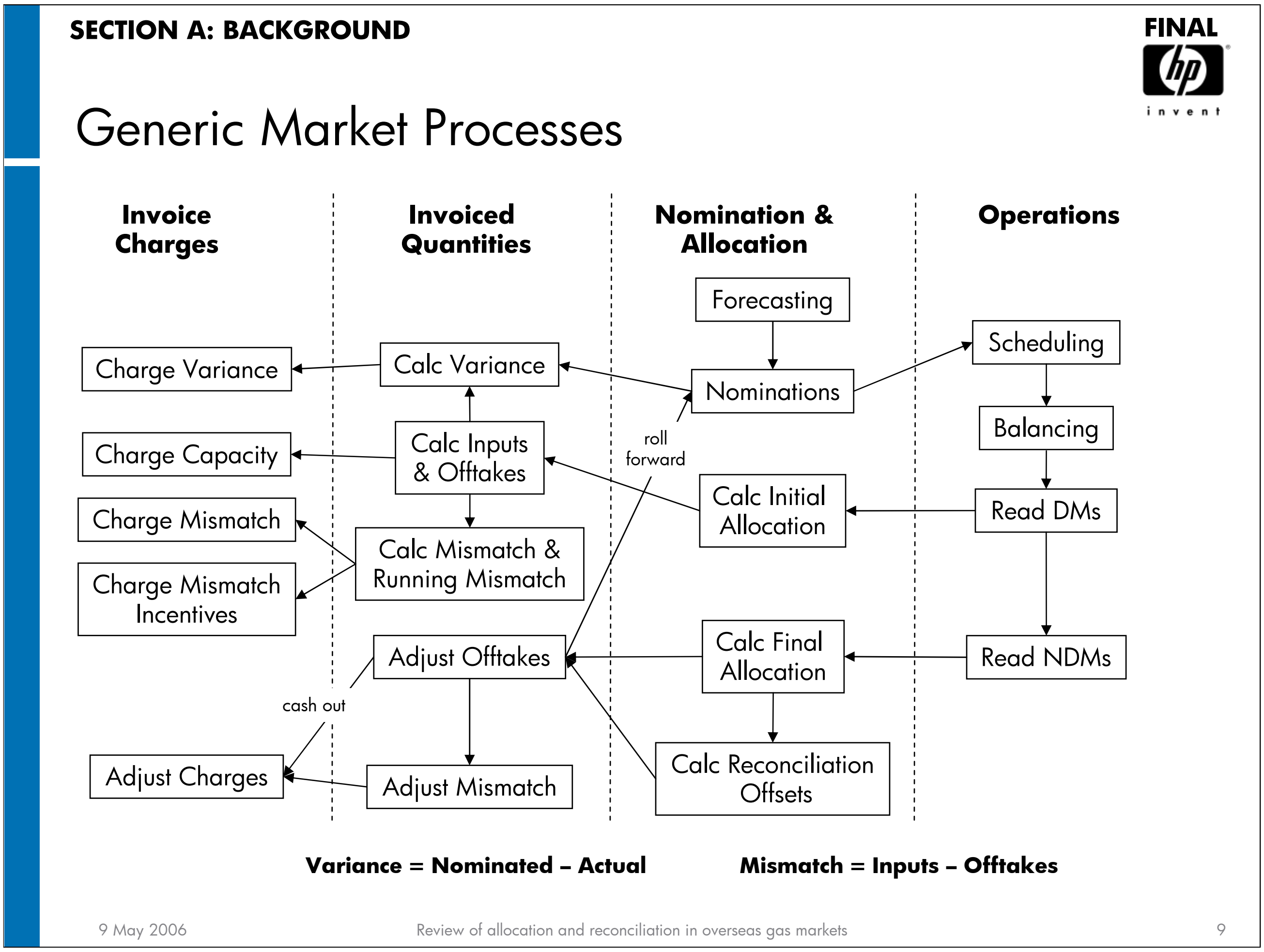
a) All retail/distribution licencees must be members of MO company and, thereby, comply with the Rules
b) 5 independent persons appointed by MO
c) Adviser appointed by MO; Panel appointed by Adviser for each dispute
d) Retailer processes must be accredited by MO before they gain access to Registry
e) Accredited by independent person appointed by MO
f) Licence requirement that all shippers sign a framework agreement with PO, which gives force to Rules
g) Compliance Panel rules on dispute interpretation of Rules; MDA decides on disputed data
h) the MO Board must decide annually whether an audit is required; MDAs must appoint an auditor annually
i) Independent expert jointly agreed by disputing parties
j) No rules-based mechanism specified; provisions may be established in each bilateral framework agreement
k) All shippers, users and pipeline operators must obtain a "gas business operator" registration from the MO
l) separate audits of MO and of DBs' metering functions
m) National Allocation Group
n) Provision for Chairman of NAG to review the Reconciliation Code but no detail on conduct of review

All markets require a governance framework which specifies how the market rules – and in particular the allocation rules – are developed, approved, interpreted and enforced. All markets other than NZ are regulated in that the requirement for transporters and shippers to comply with the market rules follows directly or indirectly from statute, generally through a licensing regime.

Rules may be modified by the MO or by a representative panel or forum of interested parties. Usually – but not always – rule modifications must be approved by the relevant industry regulator.

Rules often contain specific provisions dealing with compliance and enforcement, whereby the MO or an independent panel identifies, investigates, determines and sanctions rule breaches. Alternatively, where rules are enforced via contract, normal contractual mechanisms may apply. Similarly, disputes may be resolved within or outside the Rules.

Where the actions of shippers or their agents – in particularly those relating to meter reading and data input to the registry – may affect others, there may be a need for an "accreditation process", whereby the operational capabilities of the relevant party are reviewed. There are also generally provisions for regular or ad hoc audits of meter reading and data processing.



The three nomination/allocation timescales – forecasting, initial allocation and final allocation – dovetail with operational processes. Forecasting must take place before nominations, which is before scheduling which must be before the gas day. Initial allocation takes place after the reading of daily meters, which must be after the gas day. Final allocation occurs after non-daily-meters are read.

These quantities feed through – in various ways – into the calculation of balancing "charges" (which maybe in cash terms or in kind), which this report places into three categories:

- *variance charges*: based on forecasting errors;
- *mismatch clearing charges*: based on mismatch (the difference between aggregate inputs and aggregate offtakes for a shipper on a day) or running mismatch (the accumulation of mismatches over time); and
- *mismatch incentive charges*: based on mismatch

These charges – and their purpose – are discussed further in slide 27. The point to make here is that the variance and mismatch amounts (and hence the level of charges) will depend upon which quantities are used (ie initial or final allocation quantities). In many cases, charges will be based initially on initial quantities and then updated and reconciled as final quantities are determined. Furthermore, the time at which the charges are known will affect the behaviour of shippers in seeking to avoid or minimise these charges.

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Markets Reviewed: Process Timing

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Forecasting	D-1	D-1	D-1	D-1	D-1	D-1
Upstream Allocation	D+7	D+3	D+2(a) M+20(b)	D+1	D+1, D+4	M+6
Downstream Initial Allocation	D+5	D+3	D+1	D+1	D+1, D+4	D+1(e)
Downstream Final Allocation	After each large NDM meter read	After each read, Settled D+18, D+118	After each meter read	After each meter read +1	M+12, Y+30	M+5(c)
Downstream reconciliation offset	Monthly and six-monthly	Settled D+18, D+118	Monthly	meter read`+2	Y+30	Y(d)

a) initial allocation
b) final allocation
c) uses estimates for non-monthly meter reads. A subsequent reconciliation – based on actual reads- will take place if the allocation agent considers the changes to be material
d) May also be done after end of month if allocation agent considers it material
e) The Reconciliation Code refers to this as the "day end information service"

This slide shows the timing of the nomination/allocation processes in each market. Of course, timing in each market is constrained by the timing of the meter reading processes. As ever, there is a trade-off between timeliness and accuracy. In most markets, upstream allocation can be undertaken fairly early, since input points are usually large and few in number. Where upstream allocation is particularly complex (especially where it is dependent upon downstream allocation, as in NZ) it may be delayed. In such cases a two stage – initial then final – process is often used.

Downstream initial allocation takes place when most daily meters have been read. For customers whose daily meters have not been read, estimates are used and then reconciled in a similar manner to that used for NDMs.

Final allocation, in relation to a particular customer, can take place once the customer's NDM is read. In some markets, the consequential reconciliation of shipper quantities is undertaken daily, whereas other markets bundle a longer period (eg a calendar month) of customer reconciliations into a single reconciliation calculation.

Since retailer quantities must always aggregate to the metered quantity at the relevant offtake(s) (after allowing for UFG) each retailer reconciliation must give rise to an equal and opposite reconciliation for one or more other retailers. As discussed in slide 22, various approaches to calculating and treating this "reconciliation offset" are used and the timing of this process also varies.

Markets Reviewed: Responsible Parties

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Forecasting	PO	retailers	MO: NSL Retailers	SA: MO WA: retailers	PO	Retailers
Upstream Allocation	Shippers(a)	Shippers(a)	PO	SA:PO WA: shippers(a)	Shippers(a)	MDL(c) Shippers(b)
Downstream Initial Allocation	DB	NDMs: PO DMs: DB	MO	MO	PO	Retailers(d)
Downstream Final Allocation	DB	DB	MO	MO	PO	Retailers(d)
Demand Modelling	DB	DB	n/a	SA: DB WA: n/a	PO	n/a
Registry	DB	MO	MO	MO	MO	DB
Meter Reading	DB	DB	MDA	DB	DB	DB

a) shippers typically fulfil this responsibility by appointing and agreed allocation agent at a receipt point
b) shippers are required to appoint a gas-transfer agent to fulfil this responsibility
c) determines the amount delivered from the MDL pipeline at interconnection points
d) shippers are required to appoint an “allocation agent” to fulfil this responsibility

The party responsible for the various allocations may be the shipper, the pipeline operator or the market operator. Typically, where shippers are responsible, they jointly contract a third party – an “allocation agent” - to undertake the allocation process. For each allocation (whether at single or multiple points) there can only be a single allocation agent.

“Demand Modelling” is a process related to downstream allocation and forecasting, described further in slide 17. A demand model relates gas consumption to day of week, season and weather conditions and may be specified at the level of the customer, shipper, NSL or offtake.

One significant difference between the markets is responsibility for forecasting: it may be placed on each retailer, or may be undertaken centrally by the market or pipeline operator. The latter approach is generally taken in markets where a central demand modelling process is used in downstream allocation.

In all markets, there is a registry of customer delivery points in which customer and shipper information is held. These are managed by the market operator or DB and are accessible by retailers and meter readers.

Meter reading may be done by the distribution business or by an accredited “meter data agent”.

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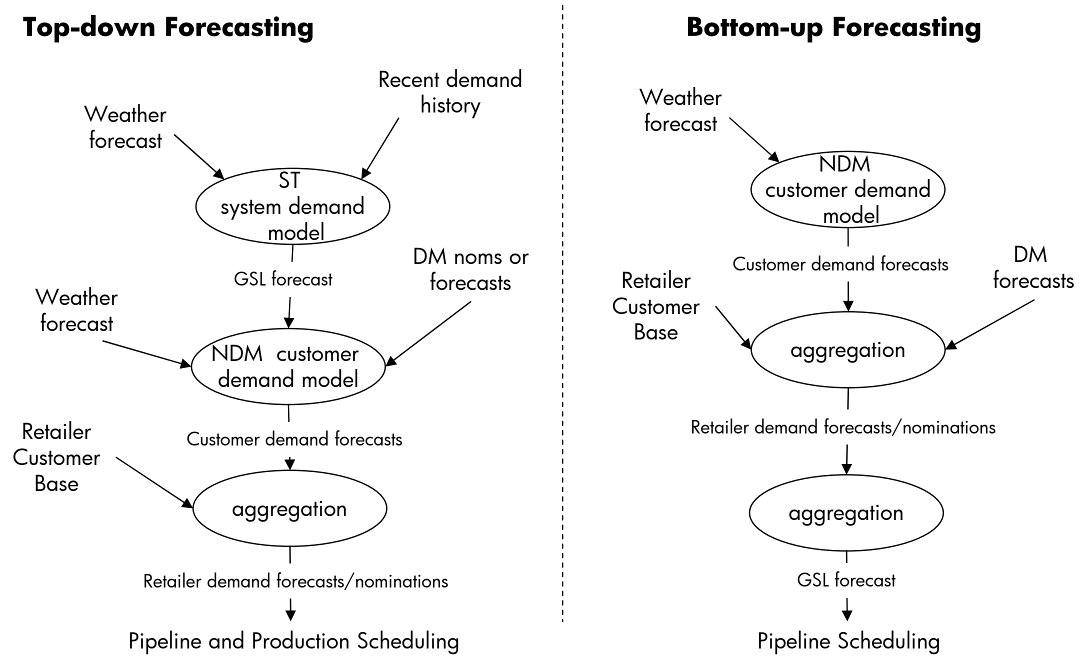
Forecasting Processes



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This slide distinguishes between two approaches to demand forecasting: "top down" forecasting and "bottom up" forecasting. Forecasting ultimately provides and input to the pipeline scheduling process, often via retailer nominations.

The "top down" approach is typically used where forecasting is undertaken centrally. The starting point is a forecast of aggregate demand at either the NSL or GSL level. This forecast is based on a "short-term" demand model which takes account of recent demand actuals - as well as the day, season and weather information utilised by other demand models - and which is typically more accurate as a result.

If this model forecasts GSL, then forecasts of DM demand (typically from retailers) are removed to give a NSL forecast. A second "customer demand model" (generally the one that is used in downstream allocation) is used to "allocate" this NSL forecast between customers. This is then aggregated to the retailer level. These forecasts are the basis for retailer nominations.

In the "bottom up" approach, the starting point is the customer demand model (which may be specific to each retailer). Customer forecasts are then aggregated to the retailer level, nominated to the PO and then aggregated to the GSL level.

The top-down process should be the more accurate, at least at the aggregate level, for a number of reasons. Firstly, a ST demand model is used. This is not really feasible for bottom-up forecasting, as recent information at the customer level (for NDM customers) is not available. Secondly, any errors arising in customer-retailer transfer processes do not affect the accuracy of the aggregate forecast. Thirdly, the central entity will typically have more resources to devote to demand modelling than an individual retailer.

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Markets Reviewed: Forecasting Method

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Approach	Top-down	none-specified(g)	Top-down(b)	SA:Bottom-up WA: not specified	Top-down	None specified(g)
GSL forecaster	Pipeline operator	n/a	n/a	n/a	Pipeline operator	n/a
NSL forecaster	Pipeline operator	n/a	MO	SA: MO WA: n/a	Pipeline operator	n/a
DM forecaster	retailer	n/a	Retailer	retailer	Retailer	n/a
NDM forecaster	Pipeline operator	n/a	retailer	SA: MO WA: retailer	PO(c)	n/a
Demand modeller	Pipeline operator	n/a	n/a	SA: DB WA: n/a	PO	n/a
Variance Charges?	Yes	Yes	No	SA: Yes	Yes(a)	n/a(f)
unbalanced nominations?	No	Yes	No(d)	No	No	n/a

a) But none on NDM forecasts if follow PO forecast
b) Forecast entity provides forecasts of NSL
c) Provides "forecast advice" to Shipper. If shipper uses these forecasts then does not pay variance forecast errors
d) Except that nomination must include adjustment components to offset running reconciliation amount, running mismatch and share of linepack change
e) But FON upstream allocation means that variance creates mismatch, which IS charged
f) Nominations not required. However, FON at the MDL:Vector interface means that variance gives rise to mismatch, which is charged
g) forecasting will still take place, of course, to inform nominations to MDL and to producers

This slide shows that the top-down approach is used where there is central (PO or MO) responsibility for forecasting and bottom-up used where responsibility is decentralised (to individual retailers). In NZ, no approach is specified but it is expected that individual retailers would use a bottom-up approach in order to prepare nominations to producers and MDL pipeline.

Where retailers have responsibility for forecasting, variance charges are usually applied, to encourage retailers to make accurate forecasts. NZ is an exception to this rule, as it does not currently have a comprehensive nominations regime (on the Vector pipeline).

Most markets require that nominations are balanced: that is, for each retailer, aggregate nominations at input points equal aggregate nominations at offtake points (after allowing for any trading, see slide 14). In these markets, retailers' forecasts will determine the level of nominations made to producers also.

Trading Types and Locations

	Before the Gas Day	On the Gas Day	After the Gas Day
Type	Forward Trading	Spot Trading	Ex-post Trading
Purpose	Procure gas to cover forecasts demand	Mitigate developing mismatches	Mismatch Trading
Counterparties	Shippers and Producers	Shippers and Pipeline Operator	Shippers
Location	Entry Points Balancing Point(a)	Balancing Point(a)	Balancing Point(a)
Use	Include in Noms	Include in Renoms and Mismatch	Include in Mismatch

a) A balancing point is a virtual or physical point on the pipeline where gas trading is deemed to take place

The markets allow various kinds of wholesale gas trading to take place. Trading may take place before the gas day ('forward"), on the day ("spot"), or after the gas day ("ex post").

Forward trading will be used by shippers to procure sufficient gas to meet forecast demand (where nominations must balance). Ex-post trading is essentially the trading of mismatch. If shipper X has +10TJ of mismatch on a day and shipper Y has -10TJ, then a 10TJ sale of gas from X to Y will reduce both shipper mismatches to zero.

Spot trading can similarly be used to offset mismatch, where shippers have real-time information on emerging sub-day mismatch quantities. This trading may also be used by the pipeline operator to procure or dispose of balancing gas.

Trading may take place at a physical location: typically an input or offtake point on the transmission pipeline. For pipelines with entry-exit transport charges (see slide 29) it may also take place at a virtual "balancing point" within the transmission system.

Trading at input or offtake points will affect upstream or downstream allocated quantities, respectively. Before-the-day trading will also affect nominations. A "final" adjustment to the allocation must be made to reflect trading. For example, if shipper X sells 10TJ of gas to shipper Y at a point, then 10TJ will be added to, or subtracted from shipper X's upstream or downstream allocation, respectively.

Trading at a balancing point does not affect allocations. However, it will affect calculated mismatch. A buy or sell trade will increase or reduce mismatch, respectively, by the traded quantity.

Trading Summary

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Timescales	Forward, spot	Forward, spot	Forward (b)	SA: ex-post(e) WA: none	Forward, spot, ex-post(a)	Forward
Locations	Entry points, balancing pt	Entry points	balancing point(c)	SA: Balancing point	Entry points, balancing point	Entry points
Balancing Trades	Yes	Yes	No	No	No(d)	No(d)

a) Until D+7
b) On D-1, to trade running mismatch
c) On the relevant network section
d) These are arranged through a tendered contract market rather than the trading market
e) Until D+1

This slide shows that all markets allow forward trading. Indeed, since such trades may be wrapped into upstream allocation methods, there is no reason (or even ability) for access arrangements to prevent this. Some markets also allow spot or ex-post trading. Such trading markets play important roles in the corresponding market designs.

Spot trading will lead to "spot prices": the prices at which these trades clear. Typically, this price will vary over the day. Therefore, daily spot prices may be quoted either as an average of clearing prices over the day (referred to here as "average price" or AP) or as the upper or lower extremes of prices over the day (referred to here as "marginal prices" or MP). Victoria's spot market is slightly different in that, although bids and offers are posted before or during the day, the market is cleared ex-post and only a single spot price is determined. Where spot markets exist, spot prices (AP and MP) are generally used in pricing balancing charges: see slide 14.

Ex-post trading is important because it will affect the way that mismatch charges are applied. For example, suppose that a pipeline is in balance in aggregate over a day, even though individual shippers may have positive and negative mismatches. In principle, ex-post trading could reduce all of these individual mismatches to zero. If such ideal trading conditions exist, mismatch quantities (and hence, other things being equal, mismatch charges) will generally be much lower than in markets where ex-post trading is not allowed or falls short of this ideal.

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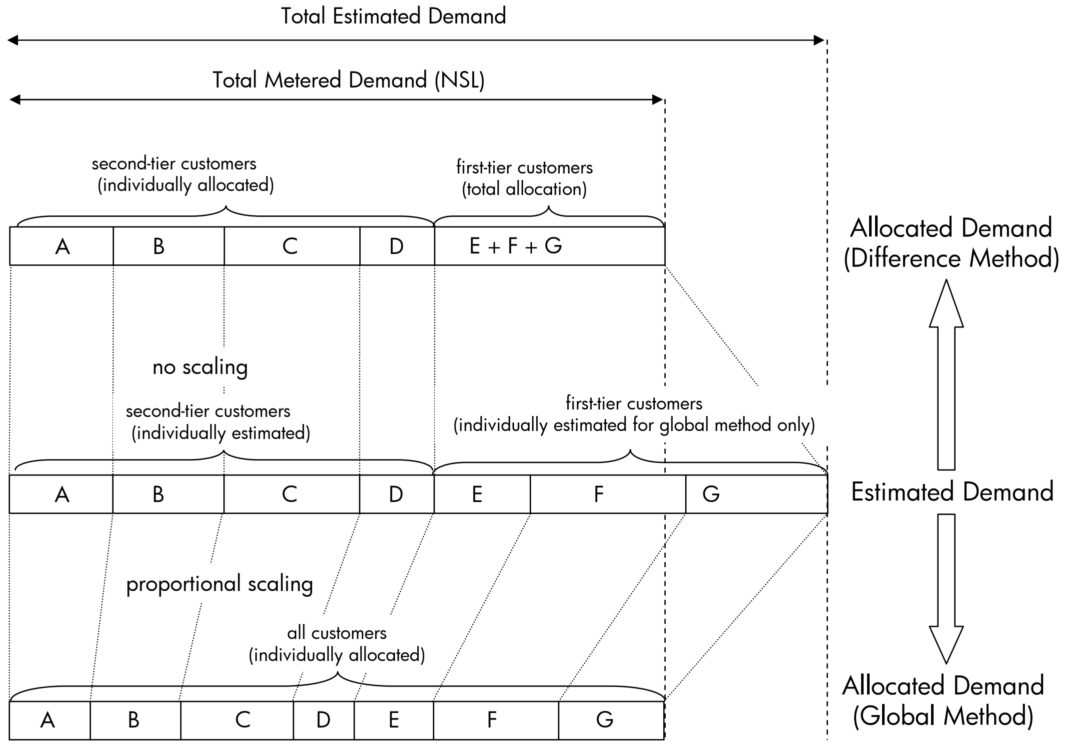
Downstream Initial Allocation methods



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Downstream initial allocation involves the "allocation" of the GSL measured at an offtake point or group of offtake points between customers downstream of the offtake point(s). Although details are different in every market, each allocation follows three steps:

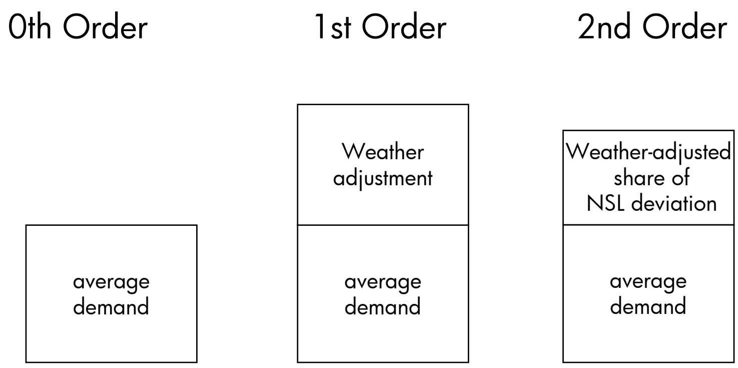
- firstly, DM quantities at customer sites, UFG and any linepack changes are subtracted from the GSL to give the actual NSL;
- secondly, each NDM customer's daily quantity is estimated (using a demand model); and
- thirdly, the estimated quantities of some or all NDM customers are adjusted to determine allocated quantities. The adjustment process ensures that the aggregate of the allocated NDM quantities equals the NSL.

Initial allocation may be "global" or "difference". In a "global" allocation process, all NDM customers' estimated quantities are adjusted using a common method. In a "difference" allocation process, only the estimated quantities of "first tier" customers – that is customers supplied by a designated "host retailer" (usually the pre-contestability incumbent) – are adjusted.

Indeed, given that first tier customers are all – by definition – supplied by a single retailer, the difference method does not require estimated quantities for such customers. Since, the allocated quantities for all second-tier (ie not first-tier) customers are set equal to the estimated quantities, the first-tier retailer's allocated quantity (in aggregate) is then simply the NSL minus all of the estimated quantities of second-tier customers.

In the global approach, estimation errors are shared across all retailers, whereas in the difference approach these errors are all allocated to the host retailer.

Estimation Models



$D_{est} = D_{ave}$

$D_{est} = D_{ave} + s * w_{act}$

$D_{est} = D_{ave} + k_{cust} * (NSL_{act} - NSL_{ave})$

$k_{cust} = s_{cust} / s_{NSL}$

Variables
D = demand
s = weather sensitivity
w = weather

Subscripts
ave = average
act = actual
est = estimated
cust = customer
NSL = net system load

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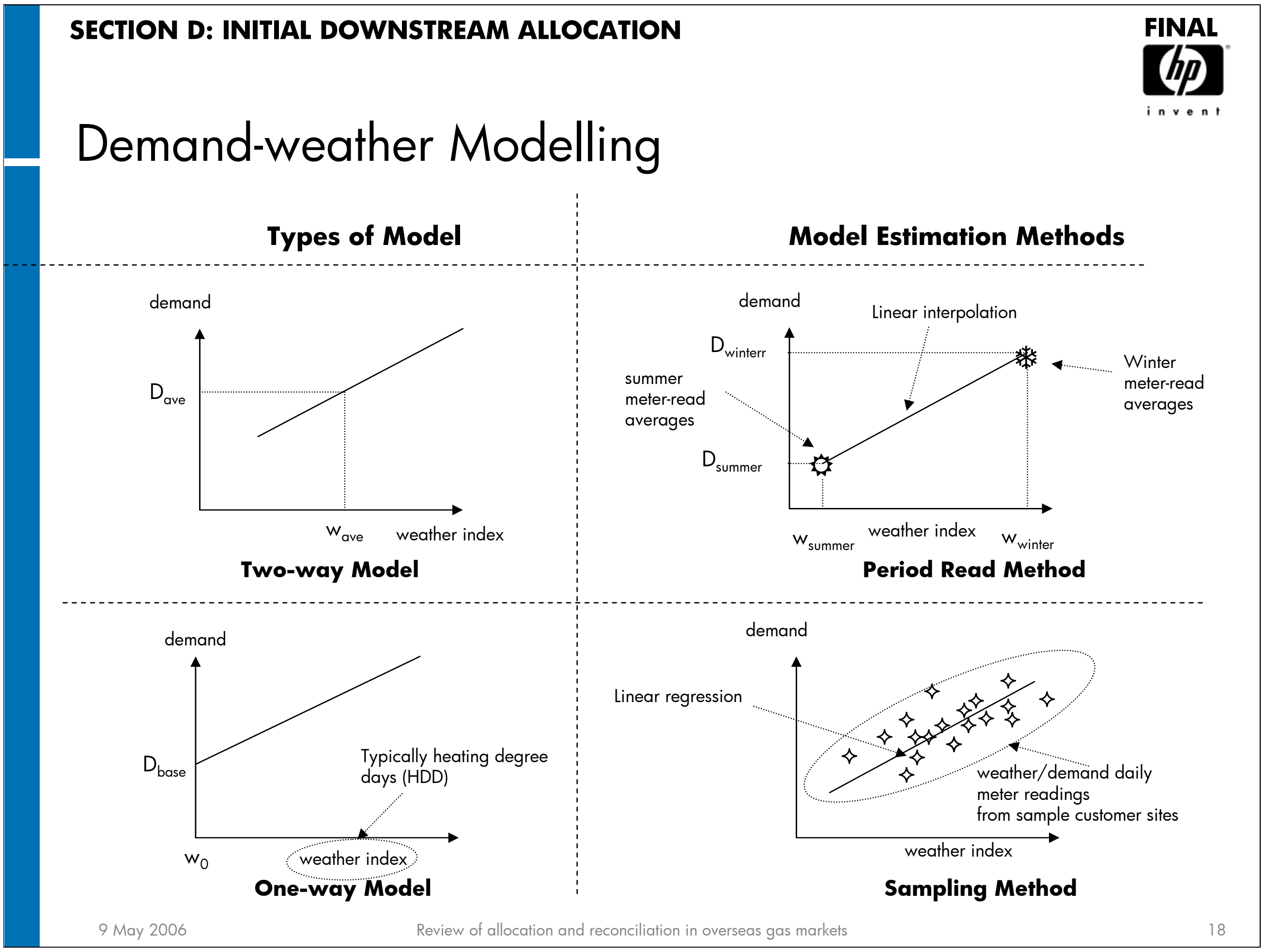
The reviewed markets have adopted a variety of approaches to estimating NDM customer quantities (as used in the second step of the process described in the previous slide). However, they all rely on mathematical "demand models" of customer demand, which can be described (in quasi-mathematical terms) as 0^{th}, 1^{st} or 2^{nd} order.

A 0^{th} order demand model has no weather component. Thus, the estimated demand is simply the modelled average demand for the particular day-of-week and time-of-year. Of course, since most NDM customers will be weather sensitive, these estimates will tend to underestimate demand on cold days and overestimate it on mild days.

A 1^{st} order demand model includes a weather component, which is linear to a defined weather index: ie the weather component is a product of the weather index (eg heating degree days or HDD) and a defined "weather sensitivity" (eg in MJ/HDD) for that customer. This model will adjust customer estimates for changing weather conditions.

The weather sensitivities are estimated using historical data (see next slide) and may be inaccurate. Thus, where the global method is used, the aggregate of the estimated quantities may still not equal the NSL. In a 2^{nd} order demand model, the weather sensitivities are automatically "calibrated" so that the aggregate matches the NSL. So, for example, if the aggregate exceeds the NSL, and the weather is colder than average, the weather sensitivities are automatically reduced for each customer, typically by applying a common scaling factor to every customer's sensitivity number.

In the order listed, these estimation methods become progressively more complex but, generally, progressively more accurate. Thus, the choice of method depends upon the cost-accuracy trade-off.



Although essentially the same model, demand models fall into two categories. The "two way" model defines the demand (for the relevant day-of-week and time-of-year) under average weather conditions and the sensitivity of demand to weather conditions above or below the average. The "one way" model, defines the "baseload" demand where the weather index (eg HDD) is zero and the weather component is then the product of the weather index and the weather sensitivity.

The method chosen for estimating the two parameters required for both of these model types depends upon the type of historical data available. Typically, for NDM customers, there are no daily-metered quantities available. In such cases, period meter readings are compared and calibrated against the average weather conditions prevailing over the corresponding reading periods. For example, in a "one-way" model, the baseload demand is usually based on the average daily quantity over a summer meter read period (when the weather component is assumed to be zero). The weather sensitivity is then determined from a winter meter read period by subtracting the baseload quantity and then dividing by the average weather index over the period.

Alternatively, model estimation can be based on sampling. In this approach, NDM customers are grouped into "categories" and daily meters are attached to a small sample from each category. Model estimation is then based on these DM quantities, together with corresponding daily weather conditions, typically using a linear regression method. The estimated parameters are then applied to all customers in the relevant category.

FINAL

Markets Reviewed: Downstream Initial Allocation

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand(c)
Approach	Global	Difference (1st Tier, 2nd Tier)	Global	Global	Global	Difference(a)
Scope of each allocation	Distribution area	Distribution area	Network section	Sub-network	Market	Distribution Area
Estimation	2nd Order	1st Order	0th Order	SA: 1st Order WA: 0th Order	2nd order	0th order(b)
Weather Model Type	two-way	one-way	None	SA: one-way WA:none	One way	None
Weather Variable	Composite Index	HDD	n/a	SA: HDD WA:n/a	HDD	n/a
Model Estimation	sampling	Period read	n/a	SA:period read	Period read	n/a
Model application	Customer category	Individual customer	n/a	SA: Individual customer	Individual customer	n/a

a) Although the host retailer may demand a change to global; indeed, some minor systems already use a global approach
b) Choice of either "static deemed profile" approach based on some DM info or "receipt point residual" (RPR) based on apportionment factors (see slide 20) from previous month
c) In NZ, the initial allocation is known as the "day end information service"

This slide shows that the markets reviewed use a variety of initial allocation methods. Great Britain has adopted the most complex approach – involving global allocation, 2nd order demand modelling and sampling-based model estimation. Of course, it is also by far the largest market and so can more easily justify a more sophisticated approach.

NZ is at the other end of the spectrum, with a difference method and a 0th order demand model. However, in NZ initial allocation is provided for information only and does not affect charges, which are entirely based on final allocation quantities.

In general, the choice of method should depend upon a number of factors:

- the size of the market, and hence the number of customers/GJ over which the fixed overheads of a particular method can be spread;
- the size and volatility of the weather component of demand compared to the non-weather component
- the market share of the host retailer: where this share is small, using a difference method with no weather modelling may place undue risks on the host retailer and so a global method and/or weather modelling is likely to be used
- the way in which the initial allocation is used in determining transportation and balancing charges

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Markets Reviewed: Unaccounted-for Gas

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
UFG estimate?	Yes	Yes	yes	yes	yes	yes
cust specific	no	Yes(a)	no	no	no	no
attributed to	DB	all shippers(c)	DB	UFG suppliers(b)	UFG suppliers(b)	all shippers(c)
cost recovery	DB tariff	n/a	DB tariff	DB tariff	DB tariff	n/a

a) Different UFG factor for customers above or below 250TJ [sic] per year
b) UFG suppliers have contracted to provide UFG and would on-charge the DB at the contracted rate
c) By scaling up the allocated quantity (at the customer point) by the estimated UFG factor

Unaccounted-for Gas in a network is the difference between total metered quantities at customer sites and total metered quantities at gate stations, after allowance for change in linepack and any own-use gas consumption by the DB. It is made up of a combination of leakage, metering errors/timing, registration errors and theft. By its nature, it is impossible to determine these components individually.

UFG must be allowed for at the initial and final allocation stages and is discussed below and on slide 24, respectively.

At the initial allocation stage, UFG is estimated to be a given proportion of total throughput for a day, with the estimated factor typically determined prior to the start of the gas year based on historical measurements of UFG. Although some components of UFG are likely to be customer-specific (eg metering error), only Victoria applies a customer-specific UFG factor.

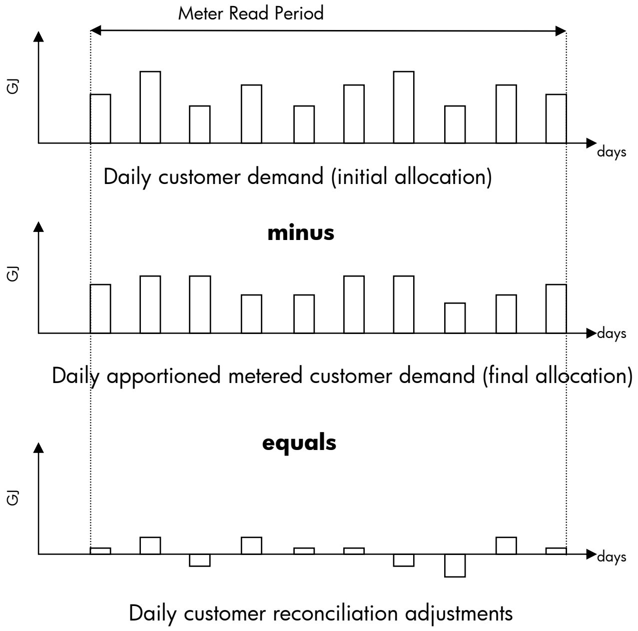
Estimated UFG may be allocated to each shipper by scaling up the initial allocated quantity at each customer site by the UFG factor to give a deemed allocation at the gate station. Alternatively, the DB may be responsible for procuring the estimated UFG. The DB may either buy gas directly from an upstream wholesale market (and, essentially, become a shipper of gas on their own network), or they may contract to buy UFG from "UFG suppliers".

Where the DB is responsible for procuring estimated UFG, it recovers the costs of this gas from retailers through its use of system charges. Typically, these costs are rolled in rather than constituting a separate component of the charges.

SECTION E: FINAL DOWNSTREAM ALLOCATION

FINAL

Calculating Final Allocation Quantities



Total apportioned amounts must equal period metered quantity

Daily amounts are proportional to a daily apportionment factor

This daily factor may be based on:

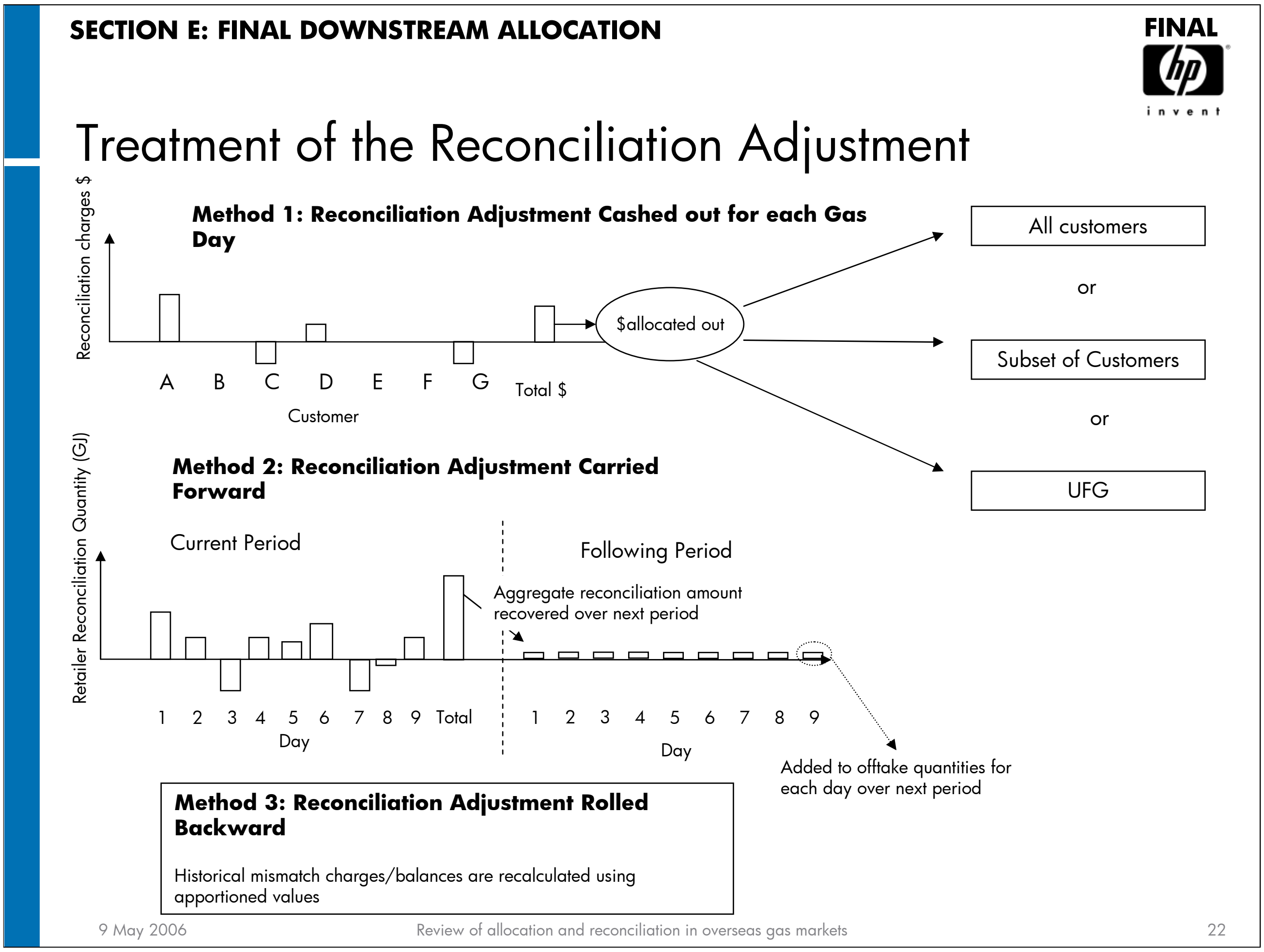
(1) NSL
(2) estimated customer quantities
(3) a constant ("flat apportionment")
(4) other (see next slide)

Final Allocation takes place separately for each customer after its NDM meter is read

Final allocation takes place when the NDM for a particular customer is read. A requirement of final allocation – in all the markets reviewed – is that the aggregate final quantity allocated to a customer over a meter reading period is equal to the metered quantity.

The various market designs usually require (Ireland is the exception) that – as for initial allocations - these final allocated quantities are determined on a daily basis. Therefore, the period metered quantity must be "apportioned" over the days it covers. This is done by defining the apportioned quantity to be proportional to a specified daily quantity (the "apportionment factor") whose values are available for the period: this may be the NSL, the estimated customer demand (from the initial allocation process) a constant (in which case the apportionment is "flat"), or some other factor. A common scaling factor is applied to convert the apportionment factor into the apportioned quantities, so that the aggregate of the apportioned quantities is equal to the meter reading.

The difference between the initial and final allocated quantities is referred to (in this report) as the "reconciliation adjustment". To the extent that charges are initially based on initial allocation quantities, these charges may need to be adjusted to reflect the reconciliation adjustment. Methods for doing this are described on the next slide.



The first approach to a reconciliation adjustment is simply to cash it out. This approach is used in markets where mismatch amounts are cashed out daily – at a specified price or tariff – rather than rolled forward into a cumulative (or "running") mismatch quantity. Typically, cash-out charges are calculated initially based on initial downstream allocations. Once the final allocation is determined, the cash-out charges are adjusted simply by levying the relevant mismatch price on each day's reconciliation adjustment amount.

However, since NDM reads are staggered, it is unlikely that aggregate reconciliation adjustments on a day will equal zero. Thus, there will be a settlement imbalance between the cash-out charges paid and received. This imbalance could be borne by the market operator, but it is typically recovered from all or some customers, pro rata to a defined and stable measure such as the previous year's annual quantity. Over time, aggregate reconciliation adjustments should average out, leaving just a small residual which reflects any error between the assumed and actual UFG quantities.

The second approach is to roll forward any adjustment into future gas days. This is used in access arrangements where mismatch amounts may be carried forward, through a "running mismatch", which must be managed back to zero over-time through offsetting future mismatches. In this approach, the aggregate reconciliation adjustment amounts for a retailer are calculated over a period (eg a calendar month) and then must be offset by an adjustment to daily nominations in a subsequent month.

The third approach (which is really a generalisation of the first approach for markets which do not cash-out daily) is simply to recalculate all charges based on the final allocation and then invoice retailers the difference between the new charges and any charges that were based on the initial allocation. In effect, the reconciliation adjustment is "rolled backward" to recalculate historical mismatch quantities.

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Markets Reviewed: Final Allocation

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Who is reconciled?	Large NDMs(j)	2nd Tier	All	all	all	2nd tier
Apportionment Factor	Adjusted estimated demand	NSL	NSL or constant (a)	NSL	n/a(b)	SDP(e) DDP(f) NSL(g)
Reconciliation treatment	Cashed out	Cashed out	Rolled forward(c)	Rolled forward(d)	Cashed out	Rolled backward
Cashout Price	Day AP	Day AP	n/a	n/a	Period AP	n/a

a) Choice of "Type A" (NSL) or "Type B" (constant): decided by GMCo
b) The reconciliation process does not require calculation of daily values
c) The reconciled quantities for a month are aggregated for a calendar month and then recovered from the same retailer in the next month through a daily adjustment quantity (1/30th of total reconciliation amount). This adjustment quantity is included in nominations and in the downstream allocation, to give a deemed "final allocation"
d) Adjustment quantities for a day are the moving average of the reconciliation amounts for the previous month
e) static deemed profile (SDP): fixed apportionment based on estimated model of a customer site
f) dynamic deemed profile (DDP): apportionment based on dynamic DM sampling for a particular customer category
g) NSL is residual after SDPs and DDPs (as well as DMs) are removed.

This slide shows that markets vary considerably on:

- which customers are reconciled (ie which have a final allocation which differs from the initial allocation);
- the apportionment factor used to determine final allocations; and
- the treatment of the reconciliation adjustments.

Victoria and NZ, because they use difference allocation, only reconcile 2nd tier customers. GB only reconciles large NDMs (customers using >8 TJ per year) and allocates the reconciliation offset to small NDMs (the rest).

GB, Victoria and Ireland all cash-out daily mismatches and so apply the cash-out method to reconciliation adjustments. NSW and SA/WA charge mismatch in-kind and so roll forward the reconciliation adjustments. NZ applies a hybrid of cash-out and in-kind charging and so rolls backwards the reconciliation adjustments.

Markets Reviewed: Reconciliation Offset & UFG

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Allocation of Reconciliation Offset	Small NDMs(c)	1st tier	n/a	n/a	UFG, shippers(b)	small NDM (d) or 1st Tier(e)
Sharing factor for reconciliation offset	AQ	n/a(a)	n/a	n/a	AQ	n/a
Who bears UFG error?	small NDM(f)	DB(g)	DB	DB(h)	DB(i)	small NDM (d) or 1st Tier(e)

a) Since all 1st tier customers, by definition, are supplied by a single (host) retailer
b) At the end of the year, UFG may be adjusted, any residual is allocated to shippers
c) large (small) NDMs are those NDM customers consuming more (less) than 8TJ/ year.
d) if allocation is "global" metered quantities of group 5 and 6 (ie <250GJ per year) customers are scaled to match the offset
e) if allocation is "difference" then the offset is allocated to the 1st tier retailer, by default.
f) Although a process of reconciling this error to the DB is also referred to, it is unclear how it operates.
g) This is done by the DB compensating retailers for any difference between actual UFG and a benchmark level of UFG specified in the Distribution Code
h) The error is attributed to the UFG suppliers who, presumably, will recover any consequential costs from the DB through their contracts.
i) Some further adjustment of the UFG factor is referred to but, again, it is unclear how this is done

Where the reconciliation amounts is either cashed out or rolled backward, there is a need to allocate the aggregate reconciliation offset, whether this is a $ or GJ amount. Where the reconciliation amounts are rolled forward, this amount is effectively added into future allocations.

In "differencing" approaches, the offset (arising from reconciliation of 2nd tier customers) is automatically allocated to the host retailer. In the UK, where only large NDMs are reconciled, the offset is allocated to small NDMs. In global approaches, the difference can be accommodated into the UFG (as in Ireland) or by adjusting the UFG factors applied to customer quantities (as in NZ, although the UFG factors of small NDM customers only are adjusted).

Once all NDM customers have been metered and reconciled, the aggregate difference between the initial and final allocations – over a period – is just the difference between the estimated and actual UFG amounts. Without any further reconciliation, this difference has already been allocated to whomever bore the reconciliation offset. However, some markets provide for further reconciliation.

For example, in Victoria, any difference between actual and "benchmark" UFG is compensated for by the responsible DB. Great Britain and Ireland provide for some further adjustment of the estimated UFG factor, although the Codes are silent on how this is done or what the effect is.

In all markets, differences between estimated and actual UFG over a year will lead to a consideration of the need for adjustment of estimated UFG in the following year.

Markets Reviewed: Treatment of Meter Errors

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
which meters checked/corrected	gate, DM and large NDM	all	gate or DM	gate or DM	gate or DM	not specified
when does individual reconciliation occur	when known	M+118(a)	when known up to D+364	as for final allocation	when known	when known
when does overall reconciliation occur	monthly, up to 12 mths after gas day	M+118(a)	when known up to D+364	as for final allocation	when known	when known
how is reconciliation undertaken	gate error: UFG adjusted other: offset allocated to small NDM	all amounts recalculated	through adjustment to NSL	adjustment to NSL and UFG	change to UFG	rolled forward(b)
whom do errors indirectly affect?	small NDM	host retailer	DB, NDMs (slightly)	UFG suppliers, NDMs (slightly)	UFG suppliers	shippers who bear UFG errors

a) And after this, ad hoc, if it is considered to be material
b) Historical allocations may be recalculated if error considered to be sufficiently material

Reconciliation to allocations may be needed if metering errors are discovered. These errors may be found before or after the normal final allocation and may arise in gate stations or at daily-metered or non-daily-metered customer sites.

Identification and correction of metering errors at a customer site will directly affect that customer's allocation. It may also indirectly affect other customer allocations, in two ways. Firstly, it will change the level of actual UFG – and hence the error between estimated and actual UFG – and this change will usually be allocated in the same way as other changes arising from NDM meter reads are allocated.

Secondly, it will affect the NSL – through which NDM meter reads are apportioned – and so will affect NDM allocations and any corresponding reconciliation offset.

Correction of metering errors at a gate station will have similar indirect effects on NSL and UFG.

Reconciliation of the directly-affected customer/retailer normally takes places as soon as the error is identified. Reconciliation for indirectly-affected customers may be delayed and "rolled-up", similar to the way that reconciliation for NDM meter-reads are rolled up.

There is usually a cut-off date for making corrections, which may be up to a year or more after the gas day. Treatment of meter errors may also depend upon the materiality of the impact.

Markets Reviewed: Upstream Allocation

	Great Britain	Victoria	NSW(e)	SA/WA	Ireland	New Zealand
Scope	Entry Point	Entry Point	Gate Station	Entry Point	Entry Point	Entry point MDL ICP
Responsibility	Shippers(h)	Shippers(h)	Shippers(h)	SA:PO WA: shippers(h)	Shippers(h)	MDL(i) Shippers(j)
Method	Contract	Contract	FON (b) or FPN (c)	SA: FPN WA: contract	Contract	FON(f) Contract(g)
Link to downstream allocation(a)	No	No	Yes (d)	No	No	Yes

a) ie through "flow-on-delivery" allocation rules
b) If metered>scheduled, FON+OI, OI sold to retailers with –ve MM, in proportion to MM
c) If metered<scheduled, FPN so no OI
d) Since allocation of OI depends upon MM, which depends upon downstream allocation
e) Describes the arrangement for Wilton Receipt Point (which supplies all the metropolitan areas) when there is no OBA in place
f) At MDL-Vector interconnection points, based on nominations on the MDL pipeline, adjusted by any trading at that point
g) At producer interconnections
h) Through an appointed allocation agent
i) responsible for providing quantities delivered to interconnection point
j) through an appointed "gas transfer agent" (ie an allocation agent)

Various methods are used for upstream allocation in the markets reviewed. The most common approach is that allocation is determined by the relevant shippers themselves based on a contract, or allocation agreement, between them. Typically, this contract will reflect the terms of the gas supply contracts with the producer at the point.

NSW and NZ markets are in a different position in that some or all of the input points are interconnections with another pipeline. At such points, allocation depends upon nominations on the upstream pipeline. The allocation must be adjusted to reflect any difference between the aggregate nomination and the metered quantity, either through a common scaling factor (in FPN) or by attributing an operational imbalance (OI) to the downstream pipeline. Where there is an OI, the downstream pipeline allocates the volume or cost of this OI to its shippers.

NSW and NZ also differ from other markets in that the upstream allocation depends upon the downstream allocation. In NZ's case, this reflects the gas supply agreements in place for Vector shippers. In NSW, it is a result of the OI being allocated in proportion to shipper mismatch which, of course, depends upon downstream allocation. The NSW situation is somewhat temporary in that it has resulted from the expiry of an operational balancing agreement (OBA) which previously existed between the two pipeline owners. The allocation arrangement is currently under review.

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Balancing Charges

	Variance Charge	Mismatch Clearing Charge	Mismatch Incentive Charge
Purpose of Charge	To reflect impact of forecast errors in scheduling costs	To settle up gas unders and overs	To reflect impact of mismatch on balancing costs
Quantities levied	difference between nominate and actual (usually initial allocation).	Difference between input and offtake quantities (usually metered allocation)	Difference between input and offtake quantities (usually initial allocation)
Aggregation	Across pipeline. Usually separate entry and exit aggregations	Across pipeline	Across pipeline
Tolerance?	Sometimes	Sometimes allowed before "cashout"	Usually
Cash or "in-kind"	Cash	Either possible	Cash
Mitigating circumstance	If operator forecast used	None	If affected by operator intervention (eg curtailment)

There are three types of balancing charges, variously applied by the markets reviewed: a variance charge and two elements of mismatch charges.

The *variance charge* is based on the difference between nominated and actual quantities, both upstream and downstream. It is intended to reflect the additional scheduling and balancing costs incurred by the pipeline operator as a result of forecast errors and hence to encourage forecasting accuracy. It usually only applies where the retailer – rather than the MO or PO – has responsibility for forecasting.

The *mismatch clearing charge* is applied where mismatch is cashed out and reflects the fact that this cashout is effectively a purchase of gas from, or sale or gas to, another party, implicitly the party with opposite mismatch or the person who has supplied balancing gas. It is levied at a rate which reflects the spot or balancing gas price.

The *mismatch incentive charge* reflects the costs associated with limitations on the availability of linepack or balancing gas on a day and is a charge over and above the mismatch clearing charge (or, where mismatch is not cashed out but is rolled forward, is a cash charge which does not clear any of the running mismatch). Usually, two prices will apply: one for positive mismatch and one for negative mismatch.

For each of these charges there may be some tolerance, allowing a shipper to incur a specified level of variance or mismatch before charges apply. Such tolerances generally reflect the ability of the pipeline system – as a result of linepack capacity – to tolerate small imbalances without incurring significant cost.

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Markets Reviewed: Balancing Charges

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Variance Price	25%*(MP-AP)	"surprise uplift"	None	SA: zone variation charge(h)	5% of AP	n/a
Variance Quantity	From allocation	initial allocation	n/a	final allocation	initial allocation	n/a
Variance Tolerance	None	none	n/a	8%	Entry: 3% Exit:20%	n/a
Mismatch Incentive Price	MP-AP	none	Balancing Gas Cost(e)	WA: $15/GJ SA: tariff charge	GB MP- GB AP	MDL incentive Cost
Mismatch Incentive Quantity	initial allocation	n/a	final allocation	final allocation	initial allocation	final allocation
Incentive Tolerance	None	n/a	None	WA: 2% of MDQ SA: 8% of DQ	Depends on entry/exit mix(a)	None
Mismatch Clearing Price	AP	AP	In kind(f)	In kind (g)	GB AP	Balancing Gas cost(c)
Mismatch Clearing Quantity	final allocation	final allocation	final allocation	final allocation	final allocation(b)	final allocation
Mismatch Clearing Tolerance	None	none	Higher of 30%, 5TJ(d)	none	none	none

a) Extra tolerance where MM caused by PO forecasting error
b) Daily price charged on initial allocations. Reconciliation quantities charged at average APs over meter read period
c) Applied only to retailers with same mismatch direction as balancing gas requirement
d) If running mismatch (excluding reconciliation amounts) exceeds this, PO may take steps to correct imbalance
e) If negative OI on a day at input point then retailer with –ve MM bears share of balancing cost
f) MM is corrected by retailer including an offsetting "imbalance amount" in future nominations
g) Previous day mismatch deducted from deemed input quantities: ie must clear imbalance on following day
h) Based on total variance across a delivery zone

This slide shows, for each market and for each of the 3 balancing charges described in the previous slide:

- the price which is applied
- the quantity which the price is applied to: in particular whether it is based on the initial or final allocated quantity (after allowing for any reconciliation adjustment charges)
- the tolerance (if any)

Note that in markets where there is a spot market, charges are based on spot prices. Interestingly, Irish balancing charges are based on GB spot prices: this perhaps reflect the fact that the GB market – being interconnected with the Irish market – is generally the supplier of balancing gas for the Irish market.

This slide is a high-level summary of the characteristics of the different balancing charge regimes. It should be recognised that these regimes are generally very complex and it is not possible to convey all of this complexity on a single slide.

Transportation Charges

	Contract Carriage	Common Carriage	Hybrid (authorised quantity)
Fixed Charge (take or pay)	Yes, on booked capacity	None	Possibly on authorised quantity
Throughput charge (on annual quantity)	Yes	Yes	yes
Overrun charge (daily quantity exceeds booked amount)	Yes, at multiple of capacity booking charge	no	Possible allocation of congestion costs
Peak charge (MDQ)	No	possibly	possibly
Quantities used for charging	Usually initial allocation	Usually initial allocation	Usually initial allocation
Scheduling priority	To booked capacity	None	To authorised quantity

Transportation charges recover the remainder of pipeliner costs (excluding balancing costs), primarily the capital cost of the pipeline assets, together with some operational costs such as compressor fuel.

Charges may be based on a "common carriage" or "contract carriage" access regime. A contract carriage regime requires shippers to book pipeline capacity in advance and pay for that capacity whether or not it is used by the shipper. If shippers flow gas in excess of booked capacity they are subject to overrun charges, typically set at a "penal" rate.

Common carriage does not require shippers to book and they are charged only for the capacity they use.

A hybrid arrangement gives shippers the choice of booking or not booking: the booked level is often referred to as the "authorised quantity". Shippers that book pay capacity charges as for contract carriage and get priority – up to their authorised quantity – in the event of pipeline congestion. Shippers who do not book, or who use more than their authorised quantity, pay transportation charges on actual use and have lower priority in the event of congestion.

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Markets Reviewed: Transportation Charges

	Great Britain	Victoria	NSW	SA/WA	Ireland	New Zealand
Structure	Entry-exit	Entry-exit	P2P	P2P	Entry-exit	P2P
Entry Type	contract	Common	n/a	n/a	Contract	n/a
Entry Quantity Charged(c)	final allocation	final allocation	n/a	n/a	Initial Allocation	n/a
Exit Type	common	hybrid	n/a	n/a	Contract(d)	n/a
Exit Quantities Charged(c)	Deemed MDQ(a)	Reconciliation	n/a	n/a	final allocation	n/a
P2P type	n/a	n/a	common	contract	n/a	contract
P2P Quantities Charged(c)	n/a	n/a	final allocation	final allocation	n/a	final allocation

a) Deemed MDQ = final downstream allocation/deemed load factor
b) Adjustment = 1/30 of prior months cumulative reconciliation amount
c) For common carriage this determines the capacity amount, for contract carriage it determines the overrun amount
d) Although the amount to be booked for NDMs is determined by the PO

Transportation charges can be based on an entry-exit or point-to-point (P2P) model. In entry-exit, shippers are charged separately for entry capacity/usage and exit capacity/usage. Since the two quantities are disassociated, entry-exit capacity models facilitate trading at a balancing point (see slide 14).

P2P models require shippers to associate particular input quantities to particular offtake quantities and are typically used where the pipeline topology is simple or radial. Tariffs are typically based on the distance between the two points.

Main Differences between NZ and international approaches

- no comprehensive nominations regime or standardised forecasting approach (no similar markets)
- no spot or ex-post markets (only NSW similar)
- no demand-weather model used in downstream allocation (only NSW similar)
- retailers have choice of downstream allocation method (no similar markets)
- downstream allocation undertaken by allocation agents rather than market or pipeline operator (no similar markets)
- upstream allocation depends upon downstream (only NSW similar, and this only temporarily)
- reconciliation adjustment rolled backwards (no similar markets)
- code compliance and modification processes not formally specified in code

There are a number of areas where the NZ arrangements differ from all, or all but one, of the markets reviewed. This is not to say that the NZ approach is wrong or inadequate. Nevertheless, it may be worthwhile investigating these areas of difference further to understand how or why they have arisen and to consider whether modifications to the NZ approach are appropriate.

The first area of difference is the absence of a comprehensive nominations regime on Vector pipelines (in fact, nominations are required at some points), although retailers are nevertheless required to nominate to the Maui producer.

The second area of difference is the lack of any spot or ex-post markets: similar only to the NSW market. The NSW regime tolerates greater levels of mismatch than the others (probably reflecting significant flexibility available from linepack) and so these markets are not necessary there. NZ has historically enjoyed similar flexibility from Maui gas.

The third area of difference is that NZ uses no demand-weather model: again only NSW is similar. Furthermore, NZ (unlike NSW) uses the difference method which allocates all of the weather-related variations to the host retailer.

Fourth is the unusual flexibility NZ retailers enjoy in downstream allocation: both in the method used and the person who undertakes it. This may reflect NZ's cultural preference for decentralised approaches – compared to the other markets reviewed.

The fifth area of difference is the dependence of upstream allocation on downstream allocation (NSW is similar but only by accident). The NZ situation arises from legacy Maui gas contracts and NZ may revert to a more "standard" arrangement when these contracts expire.

The final area of difference is the way that the reconciliation adjustment is rolled backward, which is related to the hybrid nature of Vector's mismatch charging regime.

Across the 5 markets reviewed, there is variety, but also a good deal of commonality, in the approaches to forecasting and allocation. NZ arrangements have much in common with these approaches but are somewhat unusual in a number of areas. These areas may be worthy of further investigation.